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ABSTRACT

Guidelines for colleges who may want to implement cogeneration on their campuses are presented. Cogeneration has been defined as "the simultaneous production of electric power and other forms of useful energy--such as heat or process steam--from the same facility." The history of cogeneration, current and future technologies, and cogeneration and the national energy picture are addressed. A campus needs analysis would involve establishing short-range and long-range goals, developing rough guidelines to determine whether to cogenerate, and identifying technical parameters of a basic system. After need analysis, it is necessary to work with the utility, evaluate constraints and regulations, and make a conceptual design of the cogeneration system. Stages of the conceptual design involve a broad survey, system selection, equipment selection, and capital cost estimate. Case studies for Clark University and the University of Minnesota are presented to describe how they did their conceptual design under the Department of Energy's program for demonstrating a grid-connected Integrated Community Energy System. The general problem of evaluating the plant as an investment as well as finding funds and other financial considerations are also addressed. Three stages of the cogeneration decision that are outlined are: whether to proceed with the conceptual design, whether to go on to the detailed design, and whether to implement cogeneration. Appended materials include an illustration of making a crude estimate of the cost of cogenerated electricity for the campus and comparing it with the cost of purchased electricity, a checklist on legal and regulatory constraints, a checklist on conceptual design, information on cogenerating campuses, and a glossary. (SW)

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COGENERATION: A Campus Option?

A Cogeneration Manual for Colleges and Universities

By
Robert Lloyd Goble
Wendy Coleman Goble

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Table of Contents

List of Figures iv
List of Tables v
Preface vi
Acknowledgments vii

Introduction 1
- Definition of Cogeneration 1
- Energy Waste and Energy Value 1
- Cogeneration and Campus Energy Management 2

Chapter 1 Background 4
- History of Cogeneration 4
- Current Technology 5
- Future Technologies 9
- Cogeneration and the National Energy Picture 13

Chapter 2 Conducting a Campus Needs Analysis 15
- Establishing Short-Range and Long-Range Goals 15
- Preliminary Analysis: Rough Guidelines for Determining Whether To Cogenerate 16
- Identifying Technical Parameters of a Basic System 19

Chapter 3 Steps to a Conceptual Design 25
- From Needs Analysis to Conceptual Design 25
- Working with the Utility 25
- Constraints and Regulations 28
- Conceptual Design and Case Studies 33

Chapter 4 Economic Considerations 42
- Economic Evaluation 42
- Funding and Financial Considerations 47

Chapter 5 The Decision 48
- Steps to the Cogeneration Decision 48
- When Is Cogeneration the Wrong Decision? 49

Chapter 6 The Plan of Action 50
- Getting Started 50
- Using University Talent 50
- Working with Consultants 51

Appendix A Assumptions for Preliminary Analysis of Cogeneration Potential 52
Appendix B Checklist on Legal and Regulatory Constraints 54
Appendix C Checklist on Conceptual Design 55
Appendix D Cogenerating Campuses 56
Glossary 58
Notes 62
Bibliography 63

List of Figures

FIGURE 1.	Noncondensing Steam Turbine Cogeneration System	5
FIGURE 2.	Condensing-Extraction Steam Turbine Cogeneration System	6
FIGURE 3.	Description of University of Michigan Cogeneration Plant, 1915	7
FIGURE 4.	Michigan State University Cogeneration System	8
FIGURE 5.	Dartmouth College Cogeneration System	9
FIGURE 6.	Gas Turbine Cogeneration System	10
FIGURE 7.	University of Texas Combined Gas and Steam Turbine Cogeneration System	11
FIGURE 8.	Diesel Cogeneration System	12
FIGURE 9.	Three-Diesel Cogeneration System	12
FIGURE 10.	Fuel Savings for Representative Cogeneration Systems	14
FIGURE 11.	Stage One Analysis: Heat vs. Electricity Prices	17
FIGURE 12.	Stage Two Analysis: Heat vs. Electricity Annual Use	17
FIGURE 13.	Stage Three Analysis: Minimum Fuel vs. Annual Electricity or Fuel Use	18
FIGURE 14.	Stage Four Analysis: Utility Fuel Adjustment Charge vs. Fuel Price	18
FIGURE 15.	Clark University Electric Load Distribution	21
FIGURE 16.	Clark University Heat Use as a Function of Degree Days	22
FIGURE 17.	Clark University Thermal Load Distribution	23
FIGURE 18.	University of Minnesota Thermal Load Distribution	24
FIGURE 19.	Generalized Permit Process for Each Pollutant	31
FIGURE 20.	Sample System: 1500 kw Diesel, Heat and Electricity Outputs	35
FIGURE 21.	Sample System: 900 kw Steam Turbine, Heat and Electricity Outputs	36
FIGURE 22.	Clark University Cogeneration System Estimated Fuel Savings	37
FIGURE 23.	Clark University System Block Diagram	38
FIGURE 24.	Clark University Sample Cogeneration Plant Layout	39
FIGURE 25.	University of Minnesota Cogeneration Fuel Savings	40
FIGURE 26.	University of Minnesota Proposed Cogeneration System Plant Layout	41
FIGURE 27.	Electricity and Fuel Prices	43
FIGURE 28.	Clark University Base Case Net Savings	45
FIGURE 29.	Clark University Sensitivity Analysis	46
FIGURE 30.	Electrical Load Curve	53
FIGURE 31.	Thermal Load Curve	53

List of Tables

TABLE A.	Sample Calculation Illustrating the Concept of the Value of Energy	2
TABLE B.	Typical Properties of Cogeneration Systems	13
TABLE C.	Clark Estimate of Cogeneration Likelihood	19
TABLE D.	National Ambient Air Quality Standards	30
TABLE E.	Maximum Size of Cogeneration Plants Emitting 100 Tons or Less per Year of NO_x or SO_2	32
TABLE F.	Clark University First Year Congeneration Cost Prediction	45
TABLE G.	Variables for Clark's Sensitivity Analysis	46
TABLE H.	Assumptions for Preliminary Analysis of Cogeneration Potential	52

Preface

The purpose of this manual is twofold: (1) It can help you decide if your college or university should cogenerate electricity and heat. You will have to make the cogeneration decision for your campus, but this manual can provide important guidelines. It tells you what you need to think about and how the special conditions of your institution may affect your decision.

(2) If you do decide to cogenerate, this manual can help you see what you are getting into and serve as a guide through the maze. The cogeneration process is complicated from start to finish. You have to understand the design of your present system and of your proposed cogeneration system; you have to negotiate with your utility; you have to deal with a whole set of legal and environmental problems. This manual tells you how to take these steps in a sensible, orderly way.

In line with these goals, we make no attempt to supply all the technical material you would need to design a cogeneration plant. This manual is not a do-it-yourself technical guide. But it does include enough technical detail to help you talk intelligently with the people who will do your technical design and to be used as a reference during the planning and design of your cogeneration plant.

A glance at the table of contents will make the structure of this manual clear. The various checklists and glossary in the appendices may prove useful as you go over the material.

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Introduction

Definition of Cogeneration

Both the National Energy Act and President Carter's energy speech of April 1977 define cogeneration as "the simultaneous production of electric power and other forms of useful energy—such as heat or process steam—from the same facility."

Why would you want to produce heat and electricity at the same time and in a single system? Why not use a boiler and an electricity generator, tried and true technology? The reason is that fuel is now both expensive and scarce. When you burn fuel to produce electricity, you always get byproduct heat. Why waste the heat, when fuel costs are high and fuel availability is uncertain?

Think about the usual situation. The local utility makes electricity at a generating plant by burning fuel. About one third of the fuel's chemical energy is actually converted into electrical energy. The rest is given off as heat. Now the utility has some useful electricity and a lot of useless heat. It dumps the heat into the nearest river, and then has to worry about thermal pollution. Meanwhile, your campus buys the electricity but has to burn more fuel to make still more heat.

What can you do about this waste of fuel? Chances are you don't want to move your campus to the nearest power plant outlet. Anyway, the heat output of a large plant is enough to cook a sizable campus. But you might want to move the power plant to your campus. That is the idea of cogeneration.

The three commonly used technologies are actually just scaled-down versions of what you find in a utility power plant: (1) steam turbines, which are small versions of the most-used utility generating system; (2) gas turbines; and (3) diesels. Gas turbines and diesels are used by utilities to meet peaks in the electric demand.

Remember that these are all familiar, well-established technologies. Cogeneration has been around for a long time and is not an experiment. If you choose to install a cogeneration plant, you can, if you want, get a system practically as tried and true as the more familiar boiler-plus-utility generator combination.

If cogeneration still seems exotic, here is a familiar example—your car. The engine can act like a cogeneration system in the winter. The power it produces turns wheels instead of a generator, but it also produces useful heat. True, most of the heat is lost. The exhaust heat is vented, not captured for use as it would be in a more efficient cogeneration system. The heat from the engine cooling system is also usually lost, dissipated by the radiator and fan. But any time you want to, you can use your engine for cogeneration by connecting the engine cooling system to the heater and using it to warm the car.

Energy Waste and Energy Value

You can waste energy by dumping byproduct heat in a river when you could use it to heat a building. You can also waste energy by using it inappropriately. The first kind of waste is easy to spot, as we discussed in the previous section. Inappropriate use of energy, however, is much harder to detect.

One way to recognize it is to think about the value of energy. The concept of energy value can be given a precise meaning in the science of thermodynamics, which studies the theoretical constraints on the conversion of one form of energy to another. But for our purposes it is enough to know qualitatively that energy is more or less valuable depending on how easy it is to convert to other forms of energy.

Thermodynamics tells us that electricity, chemical energy, and mechanical energy are more valuable than heat, and that the value of the heat in a heat reservoir is greater when the temperature is greater. For example, electricity is easy to turn into heat or other forms of energy, such as light or the mechanical energy produced by an electric motor. You can convert electricity to heat with 100 percent efficiency. Heat, on the other hand, is very hard to convert into electricity or mechanical energy. The best practical efficiency you can get by consuming fuel to generate electricity is about 40 percent. Electricity, then, is both more useful

and harder to make than heat, and consequently more valuable.

By the same token high-temperature heat is more valuable than low-temperature heat, since the former can be converted more efficiently and easily into electricity or other forms of energy. There isn't much you can do with heat at room temperature, except warm a room.

You can keep a room warm with low-temperature heat, but it is a waste to use heat of a higher energy value that you might be able to use some other way. It is wasteful, for instance, to heat buildings by burning oil. The very hot oil flame could be used to make electricity first, and the leftover heat could warm the building. Using electricity for space heating is even more wasteful and inefficient.

The concept of energy value means that simply figuring out the efficiency of a process or machine is not enough. The more efficient process or machine may be more wasteful because, even though it produces more energy for a given amount of fuel, that energy is in a less valuable form.

For example, suppose you have a very efficient steam boiler. It converts 80 percent of the energy of the fuel it burns to heat in steam, which you use at low temperature to heat your campus. You can compare it to a typical diesel generator. The diesel might produce electricity with 30 percent efficiency and heat with 40 percent efficiency. Obviously the boiler is the more useful machine, right?

Wrong. Look at the whole picture. Suppose you feed the boiler a million British thermal units (Btu) of fuel. Out will come 800,000 Btu of heat, which you use at low temperature. To get the same amount of useful heat from your diesel, you have to feed it twice as much fuel, two million Btu.

But for that two million Btu of fuel you also get 600,000 Btu, about 175 kilowatt-hours (kwh) of electricity. Your boiler does not give you any electricity, so you have to pay the utility for it. Because electricity is hard to make, the utility's best generators will be about 40 percent efficient. To supply you with 600,000 Btu of electricity, they have to burn one and a half million Btu of fuel. Part 1 of Table A gives the results.

Of course, there are other ways to take advantage of the high temperature of an oil flame; you don't have to use a diesel engine. The boiler itself can provide steam at a high temperature and pressure. Before using the steam for heating purposes, you could pass it through a turbine and generate electricity. Part 2 of Table A gives a second comparison between the boiler-steam turbine system and the boiler-utility combination with similar results.

So, if you insist on using a boiler just to obtain low temperature heat, you will have to burn more fuel to get an equal value of energy, quite apart from the relative efficiencies of boilers, diesels, and utilities. Knowing about energy value can help you avoid energy waste.

What can you do specifically to avoid waste? You can stop dumping energy by using the familiar conservation practices: insulation, storm windows, timed light switches, etc. You can stop misusing high quality energy by keeping away from electric resistance heating and using heat pumps (air conditioners running backwards) instead. But one of the best ways to stop wasting high value energy is to cogenerate.

Cogeneration and Campus Energy Management

Cogeneration can be a great benefit to a campus energy management program, because it saves both fuel and money. To reap the savings, however, you have to

*TABLE A
Sample Calculation Illustrating the Concept of the Value of Energy

PART 1

	Input, fuel (Btu)	Output, heat (Btu)	Output, electricity (Btu)
Boiler	1,000,000	800,000	—
Utility	1,500,000	—	600,000
Total, boiler + utility	2,500,000	800,000	600,000
Diesel	2,000,000	800,000	600,000

PART 2

Boiler	1,000,000	800,000	—
Utility	350,000	—	140,000
Total, boiler + utility	1,350,000	800,000	140,000
Boiler-Steam Turbine	1,200,000	800,000	140,000

*This table illustrates the concept of energy value and how it differs from efficiency. Part 1 compares a boiler used only for heating with a diesel which provides both heat and electricity. The boiler is more efficient than the diesel, since it produces 800,000 Btu of energy for 1,000,000 Btu of fuel (80 percent efficiency). The diesel only produces 1,400,000 Btu of energy for 2,000,000 Btu of fuel (70 percent efficiency). But the boiler, in this example, produces only low-value energy, namely heat for your campus, while the diesel produces 600,000 Btu of high-value energy, namely electricity, in addition to 800,000 Btu of heat. To make the same amount of electricity, the utility has to burn another 1,500,000 Btu of fuel. So, to produce energy of the same quantity and the same value as the diesel, the boiler-plus-utility system has to burn 500,000 Btu more fuel.

Part 2 makes a similar comparison between a boiler used just for heating and a boiler-steam turbine combination that also produces electricity. Again the straight boiler is more efficient, 80 percent versus 78 percent, but the boiler-steam turbine combination produces 140,000 Btu of electricity, which would require 350,000 Btu of fuel to be burned at the utility. To produce energy of exactly the same quantity and value as the boiler-steam turbine combination, the boiler-plus-utility system must burn an additional 150,000 Btu of fuel.

pay the price. If you decide to cogenerate you limit your flexibility for the future. You have to make some energy management decisions and stick with them.

One limitation on your flexibility is that a cogeneration plant is a major investment. Because it ties up more capital, you won't be able to change systems easily. If you invest in a cogeneration system now, you may not be able to install solar heating next year, or any other system for many years.

This is probably not a severe limitation. Although you don't have quite the selection you would with the conventional boiler-plus-utility generator system, you do have a fair number of alternatives. And no major breakthrough is likely to happen soon enough to make you sorry you invested. Large solar installations and other exotic systems are at least ten years from commercial viability. So are most of the new cogeneration technologies described in Chapter 1. Consequently, you get to choose among all the technologies likely to be available for a while and you want to make sure you choose the right one.

There is one other limitation on your flexibility. Cogeneration systems are much more sensitive to load fluctuation than conventional systems. While boilers usually perform quite well at part loads, the performance of cogeneration systems frequently falls off considerably as the load decreases, so it is important to balance supply and demand for electricity as well as heat. You have to choose the right size of system, within fairly narrow limits. That also means you have to make careful predictions of your future energy needs.

Cogeneration can limit the flexibility of your energy management plant. But there is a lurking benefit to the limitations. Planning for cogeneration forces you to think seriously about how you supply energy services to your campus. You want to choose a system that will fit the demands of your particular institution. But, as you add new end-use equipment, you also have a chance to adjust the mix of heat and electricity demand on campus to fit your cogeneration system as well as possible. For instance, you can choose to air-condition a new building by absorption cooling, thereby increasing your thermal demand, or by electricity, increasing your electrical demand. By continuing to adjust the mix over the life of your plant, you can save still more fuel and money.

These matters are dealt with in greater detail in Chapter 2.

Whether or not you choose to cogenerate, remember that a vigorous conservation program in your buildings can reduce your energy demands 25 to 50 percent. If you haven't been working actively on conservation, you probably aren't ready to install a new cogeneration system.

CHAPTER 1

Background

History of Cogeneration

Cogeneration uses established technology and familiar concepts. Why then, is there such a fuss about it right now? Cogeneration can save money and energy. Why have recognition and development been so slow? The answers lie in the history of heat and power generation in the United States.

Cogeneration and power generation began together. Only later did power and steam generation separate. The case of Southeast Missouri State University is instructive. According to a recent conference report:

> The Board of Regents' minutes for the academic year 1880-81 reflect that the then 'Normal School' was heated by burning wood, coal, and catalogues in stoves and fireplaces. Some six years later the decision to install steam heating was made and by 1903, steam piping tunnels and steam-engine driven, direct current, electric generators were in service.[1]

The system continued to evolve and is still in use today, the oldest continuously operating college cogenerating system. It is unusual now, but, when it was established at the turn of the century, most industries and other institutions produced their own electricity and steam by cogenerating. When independent urban power companies were established, they followed suit.

As long as boiler pressures were low, this was economical, to the point where it was cheaper for utilities to dump the steam condensate than to construct return piping. The new, higher pressure boilers were a different story, however. True, they were much more efficient, but they required pure water. Water treatment, simple and cheap for low pressure boilers, became complicated and expensive. Rather than investing in condensate return piping or elaborate water treatment facilities, most utilities simply stopped selling steam in the 1920s.[2] A few, like Con Edison of New York and Boston Edison, still sell steam. But such service is frequently a fossil remnant, and the steam is often produced in low pressure boilers quite independent of the power generators.

More slowly, industries and institutions, while continuing to generate steam, stopped making electricity. Power produced by generators other than utilities dropped gradually to 15 percent in 1950 and to 5 percent in 1973.[3]

There were three main reasons for the drop in production of industrial power.[4] First, as electric utilities grew stronger and gained monopoly privileges, they actively encouraged increased electricity use and discouraged outside generation. They set up declining block rate schedules, offering lower costs to large users. Declining block rate schedules encouraged electricity consumption and improved the utilities' load curve, but they also removed much of the incentive for large users to cogenerate. The utilities instituted high standby charges, making utility backup for outside generation expensive. Electric utility companies were helped, and in part justified, by declining fuel prices, which made capital costs proportionately more significant. The resulting economies of scale were available only to large power plants.

Second, the increasing availability of oil and gas stimulated the development of package boilers in the 1940s. They were much cheaper to install than the old coal-fired, field-assembled boilers, and they needed much less supervision, but they ran at pressures too low for economical electric power generation.

Third, the increasing economic squeeze encouraged poor management of industrial power plants. A study by the Dow Chemical Corporation describes what frequently happened.

> Power plant maintenance usually comes in infrequent, but expensive doses. In the desire to keep up production levels, the uninitiated manager may attempt arbitrary economies, which may appear successful because a power plant normally has substantial built-in reserves. Continuation of this practice, based upon its apparent success, can bring the manager to a point at which he suddenly finds himself without a functioning power plant. A large

number of industrial plants have abruptly connected to the utility on a crash basis following the above scenario. The process has seldom been reversed.[5]

Economic and technological pressures encouraged the split between steam production and power generation. Economic and technological pressures are now mending the split. Since the oil embargo of 1973, rising fuel costs have made the fuel efficiency of cogeneration increasingly attractive.

The related recent escalation of costs for large power plants has also shifted the balance. In a reversal of earlier economic events, high fuel costs have reduced the proportionate significance of capital costs in power generation. As a result, economies of scale, which favor large utilities, are less important. At the same time, rising construction costs have made it harder for utilities to expand.

The new regulatory climate has also affected utility attitudes. The most significant recent change has been the Public Utility Regulatory Policy Act (PURPA), 1980, as interpreted by the Federal Energy Regulatory Commission (FERC). This requires electric utilities to purchase power from qualified cogenerators (definition on page 26) at a price corresponding to the utility's avoided costs.[6,7]

Utilities are responding to these internal pressures and to the prodding of regulatory agencies by becoming more receptive to cogeneration.

Technology now favors cogeneration, too. Industries and other institutions can choose from a number of diesel, gas turbine, or steam turbine generators with heat recovery systems. Those institutions responding to current pressures to switch back to coal can add the capability for cogeneration relatively inexpensively while they convert.

It is interesting to compare what has happened in the United States with the results of very different economic pressures in western Europe. There, fuel has always been expensive and cogeneration is far more usual. West Germany cogenerates nearly 30 percent of its electricity, and the Scandinavian countries have developed pioneering district heating systems in which electric companies provide steam and hot water for homes, institutions, and industries. A significant portion of the heat and power is generated by burning solid waste; this both lowers fuel costs and reduces the demand for landfill.

Current Technology

This section describes the three currently available systems: steam turbines, gas turbines, and diesels. Which system is best for your campus depends on considerations discussed in Chapter 2.

Steam Turbine Systems

A noncondensing steam turbine acts like a pressure-reducing valve. Steam from a high-pressure boiler powers a turbine which runs a generator. The steam is then exhausted at the working pressure of the heating system. If the steam flow is controlled by the steam load, the turbine is called a back-pressure steam turbine. Boilers for steam turbines can take any fuel. Figure 1 shows a block diagram for a noncondensing back-pressure steam turbine system.

An extraction noncondensing steam turbine extracts steam at one or more intermediate pressures (single, double, or multistage extraction turbine), which gives added flexibility for meeting campus

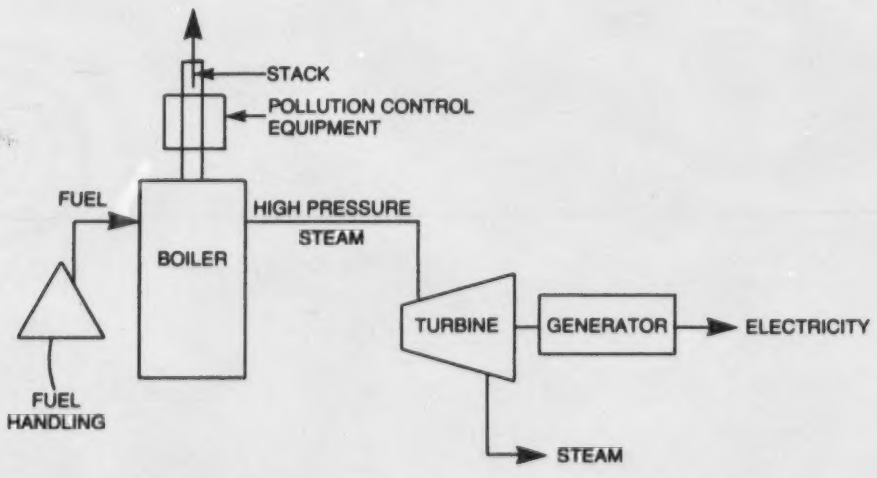

FIGURE 1. Noncondensing Steam Turbine Cogeneration System

thermal needs and balancing the ratio of electricity to steam. The extraction of steam at a given pressure is automatic if the output can vary with demand on the system. It is uncontrolled if the output at that pressure is fixed.

A condensing steam turbine is like a noncondensing steam turbine except that the output of steam, which is at too low a pressure to be used, is condensed and returned to the boiler. The heat of condensation is dumped into the environment. Like noncondensing units, condensing steam turbines are available with one or more stages of steam extraction, and can be automatic or nonautomatic. The condensing stage of a turbine is not economical for a university to operate steadily since it wastes too much heat. The flexibility of a condensing turbine can, however, be useful in meeting short term increases in electricity demand or in peak shaving (reducing electricity bills by reducing peak demand). Figure 2 shows a block diagram for a condensing-extraction steam turbine system.

Steam turbine cogeneration systems are by far the most common on university campuses, particularly on large ones, for both practical and historical reasons. As a practical matter, steam turbines are easier to integrate with university boiler plants as they can use any fuel and produce any combination of steam pressures and/or hot water temperatures. As a historical matter, for many years turbines were the only practical electrical generating system. In the early days, before electricity utilities were fully developed, quite a few universities started cogeneration plants. Figure 3 shows a page of the University of Michigan campus guide of 1915, describing their truly up-to-date steam boiler and turbine generating plant. When the University of North Carolina power plant was built in 1940, it provided almost all the electricity not only for the campus, but for the towns of Chapel Hill and Carrboro as well. The plant was still providing about 8 percent of their electricity in 1976, when the distribution system to the towns was sold.

Present day university steam turbine systems are usually complicated. A typical system might have several boilers connected to two or more steam turbines. The Michigan State University main power plant, for example, has three large boilers and three extraction condensing steam turbines. Steam from each boiler can go into any turbine. The plant was built in 1965, with a major addition in 1975, burns coal primarily, and provides almost all of the university's electricity load. Figure 4 shows a block diagram of the plant and specifications for the major equipment.

The Dartmouth College plant is an interesting example of a much smaller plant. One high pressure boiler serves two steam turbines; three other boilers can serve one small turbine, but mainly provide back-up and cover winter peaks in the heat demand. The university installed the high pressure boiler-turbine system during a major campus building program which included plans for a second high pressure boiler. Energy conservation sparked by the oil crisis has made the second boiler unnecessary; consequently, the turbine system is somewhat oversized. The plant burns residual oil, and generates 50 percent

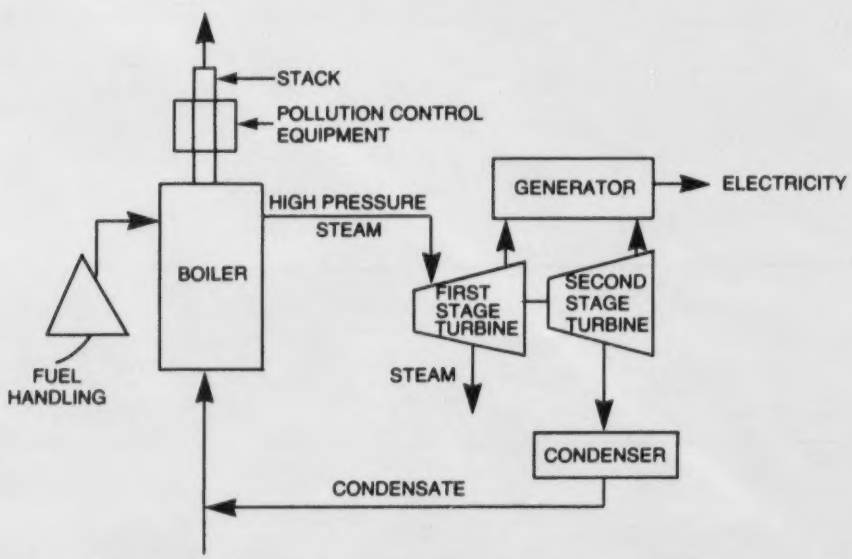

FIGURE 2. Condensing-Extraction Steam Turbine Cogeneration System

48 *University of Michigan*

POWER PLANT.

East Washington Street, northeast of campus. Cost thus far, over $400,000. Dimensions, 194 by 107 feet, divided lengthwise by a fire wall to form boiler room on the west and engine room on the east. Besides furnishing heat and light for campus and other university buildings, the power plant supplies compressed air, electrical energy, and high pressure steam for laboratory purposes. Fully equipped with labor-saving devices. Electric locomotive used to haul coal cars from Michigan Central tracks. An electrically operated traveling crane unloads the coal into an outside storage bin of 2,000-ton capacity, from which it is mechanically elevated, crushed and dumped in steel bunkers of 500-ton capacity, over the boiler room, from which it is measured into the grates. Ashes are removed automatically through a large suction pipe into a twelve-ton ash container above the railroad spur on the west side of the building, and there dumped into cars for removal. Fifteen thousand tons of coal per year will thus be handled without the use of hand labor. Eight 400-horse-power Wickes vertical boilers are used, each boiler registering its cost of firing. Two large feed water heaters supply boiling water to the boilers, thus eliminating all possible waste of heat. Each heater has a capacity of 12,000 gallons per hour at a temperature of 212 degrees. The power plant is connected with the campus by means of a tunnel, over a quarter of a mile long and ten feet high. This tunnel is joined to the ramifications of the old tunnel which distributes heat and light to the various buildings. Only three men are required to run the plant at any one time, an engineer, a stoker, and a water boy. As these men work in eight hour shifts only nine men are required to operate the plant.

Figure taken from the *University of Michigan Campus Guide Book*, January 1915, Vol. XVI, No. 13.

FIGURE 3. Description of University of Michigan Cogeneration Plant, 1915

of Dartmouth's electricity. Figure 5 shows a block diagram of the plant.

Small steam turbine systems are significantly less efficient than larger ones. As a consequence, campuses smaller than Dartmouth's should not expect to meet very much of their electrical demand with a steam turbine system. There can be circumstances, however, when even a small school might wish to install a steam turbine. Bucknell University, for instance, received a used 600 kw turbine generator as a gift from Westinghouse and runs it during the winter heating season to produce about 7 percent of their electricity.

The operation of campus steam turbine plants depends crucially on the university's relationship with the electric utility. The Ohio State University generated no electricity last year, since it was cheaper to purchase electricity than to generate it. Next year they will use their 14 mw of steam turbine capacity for peak shaving, as their new contract with the utility has a higher demand charge. Oklahoma State University has three extraction steam turbines and one condensing nonextraction steam turbine. Because of its high operating costs, the nonextraction turbine is used only for emergency standby and peak shaving. Although Dartmouth does not have condensing turbines, they peak shave similarly by dumping some excess steam in the summer. Michigan State University, however, does find it economical to run condensing turbines when their demand for electricity exceeds the steam demand. When there is sufficient steam demand they generate more electricity than they can use and they sell the excess to the utility.

Gas Turbine Systems

Gas turbines are the most recent of the cogeneration systems. A gas turbine is a conventional aircraft jet engine modified so its turbine runs a generator. The most common heat-recovery system runs the jet engine exhaust through a waste heat boiler. Since exhaust temperatures are 700°F or more, they can easily generate 200 psig steam, the highest a college system is likely to use. Gas turbines normally take natural gas or diesel fuel (No. 2 oil, distillate oil), but some of them can burn residual (No. 6) oil if the oil is treated. The basic configuration is shown in Figure 6 (page 10).

Another possible heat-recovery system runs the exhaust into the combustion air intake for an auxiliary boiler. With this option, you might be able to modify an existing boiler rather than buying a new waste heat boiler, and you probably would get comparable amounts of heat. You have to check carefully to see whether it is feasible, however.

Gas turbines can stand alone in cogeneration systems or be combined with steam turbines. The University of Texas has one 15 mw gas turbine, which powers a waste heat boiler, and three automatic extraction noncondensing steam turbines (1-25 mw, 2-5 mw) powered by seven boilers including the waste heat boiler. Figure 7 (page 11) shows a block diagram for the system. The entire plant burns natural gas as its primary fuel and provides most of the university's electricity.

Diesel Systems

A diesel is an internal combustion, reciprocating engine in which fuel compression sparks ignition. In a diesel system, the diesel turns a generator directly. Just as in a gas turbine system, exhaust gases at 700°F power a waste heat boiler to produce high-pressure steam. The jacket (engine block) cooling system generates additional heat, which can be in the form of 160-

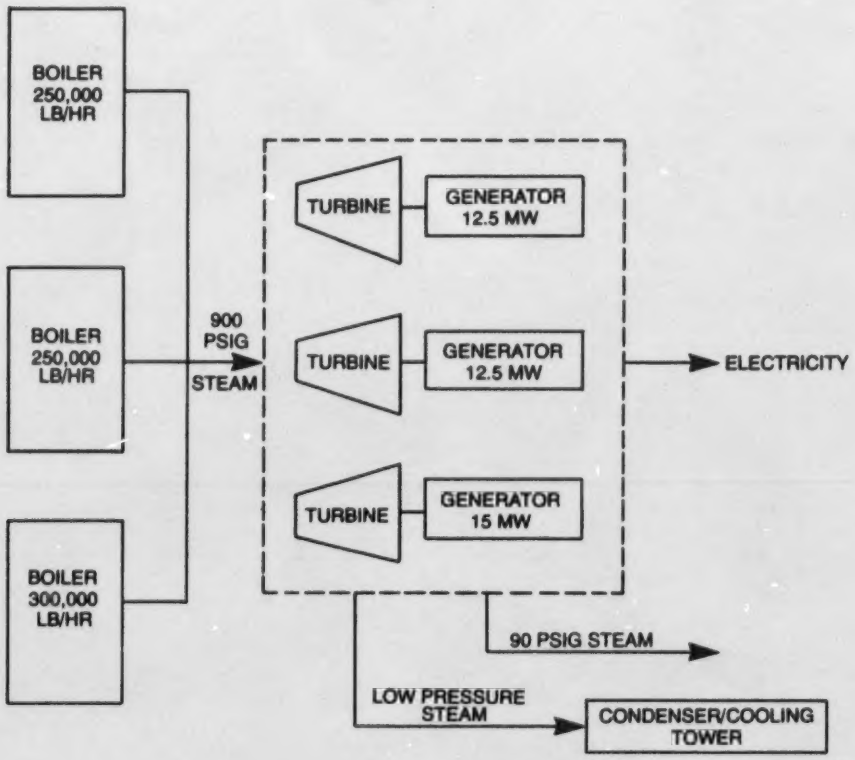

FIGURE 4. Michigan State University Cogeneration System

200°F water or, if the diesel is ebulliently cooled (cooled by boiling water), of low-pressure steam, up to 15 psig. Because jacket heat can't be above about 250°, there may be problems using it in heating systems designed for high-pressure steam. Diesels, like gas turbines, burn distillate oil, natural gas, or properly treated residual oil. Strictly speaking, the natural gas-burning engine has an ignition system and therefore is not a diesel, but for practical purposes the gas engine can be included with diesels. A diesel system is shown in a block diagram in Figure 8 (page 12).

In the past the most common use of diesel engines for cogeneration systems has been for fairly small facilities in total energy systems. These are designed to provide all electricity and thermal needs independent of the electric utility. Such systems require several engines to provide backup for maintenance and for equipment failure and to meet a wide range of loads. Figure 9 (page 12) shows a block diagram for a system based on three diesel engines. At most, two engines would be in operation at any time, with the third available for emergencies.

General Considerations

The three basic technologies, steam turbines, gas turbines, and diesels, differ in the fuel they can use, in their relative outputs of heat and electricity, and in their efficiency. These properties determine which type of system is most suitable for a particular application. Table B (page 13) gives typical values for each technology and lists advantages and disadvantages of each.

Steam turbine systems have the greatest overall efficiency. But most of their input energy is rejected as heat rather than electricity, so the value of the energy produced, as discussed in the Introduction, is relatively low. Diesels are highest in value of the energy produced. This difference in value of energy produced shows up in the fuel savings of each system. The net fuel savings may be found after calculating the reduction in the electric utility's fuel use as a result of operation of the cogeneration system. Savings for representative systems are illustrated in Figure 10 (page 14). Because the different types of systems produce different ratios of heat and electricity, comparisons

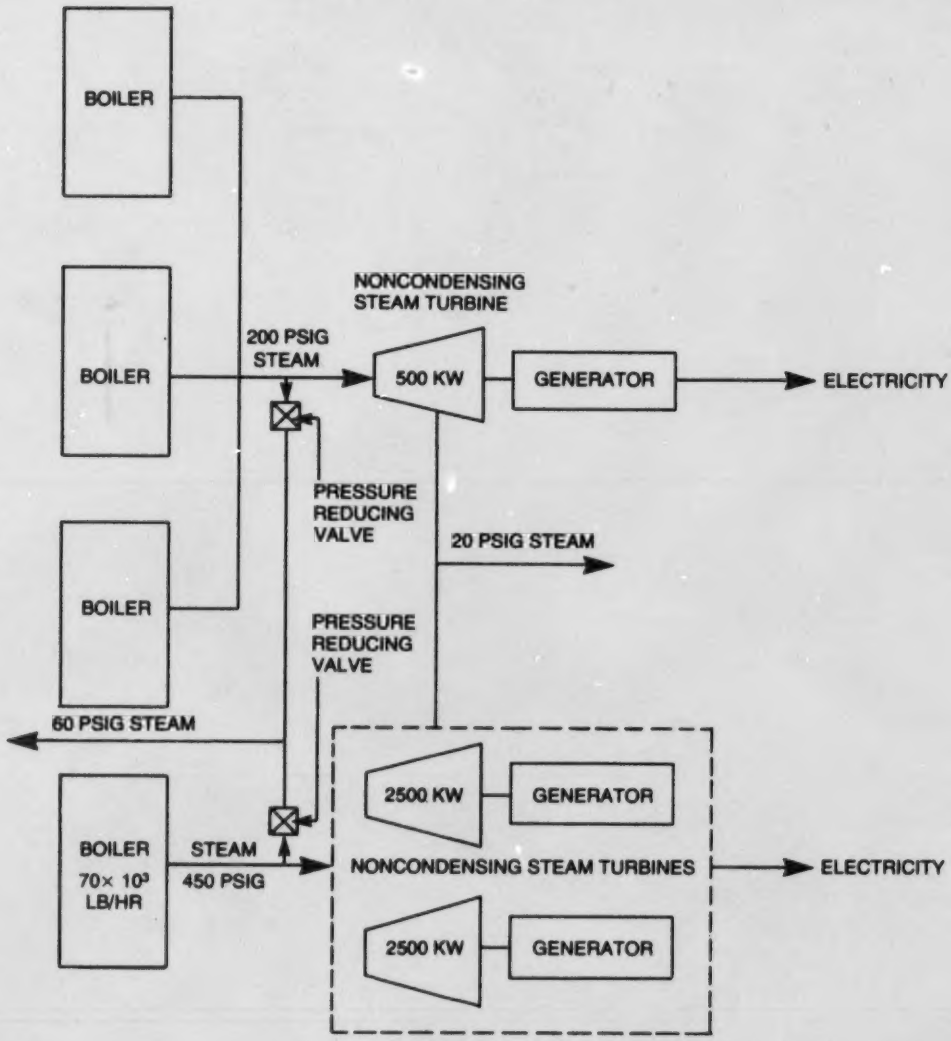

FIGURE 5. Dartmouth College Cogeneration System

between them are necessarily arbitrary. In Figure 10, we have chosen the fuel input to be the same for each system. Of course, in designing your system, you would choose a technology based on your mix of electrical and thermal needs, your arrangements with the electric utility, and the nature of your existing equipment.

Future Technologies

This section reveals what you'll be missing in the future if you cogenerate now, but don't hold your breath. Most of the new engines and techniques won't make any commercial impact for nearly ten years, perhaps even longer. So unless you find a demonstration program and decide you want to take part in it, think of these technologies as possible replacements when your current cogeneration system wears out.

Coal-Fired Diesels

Around the turn of the century Mr. Diesel himself burned pulverized coal in one of his new engines. Diesels can run on many fuels and mixtures, but the problem is to keep them running. Pistons, rings, and cylinders deteriorate rapidly with the wrong fuel.

In the interest of conserving oil, the Department of Energy (DOE) and several industries have a joint pro-

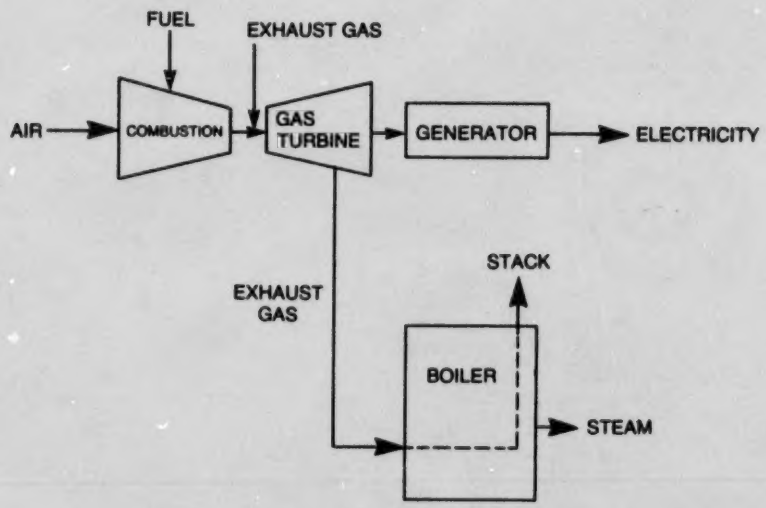

FIGURE 6. Gas Turbine Cogeneration System

between them are necessarily arbitrary. In Figure 10, we have chosen the fuel input to be the same for each system. Of course, in designing your system, you would choose a technology based on your mix of electrical and thermal needs, your arrangements with the electric utility, and the nature of your existing equipment.

Stirling Engine

This is an external combustion engine, so, like steam turbines, it can burn anything. The Stirling engine has other advantages as well. External combustion makes pollution control easier. Fewer moving parts may mean quieter and more reliable operation. Only small engines for mobile use have been built so far. Larger ones suitable for cogeneration are under development, but they are still at least ten years from commercialization. Thermal efficiency for the larger units should be somewhat better than for diesels; electrical efficiency should be about the same.[8]

Fuel Cells

Fuel cells produce electricity directly from chemical reactions much as a battery does. Currently fuel cells are fueled with hydrogen or natural gas (methane) and use platinum as a catalyst. Fuel cells that run on heavier hydrocarbons (heavy oil, coal-based fuel) are in development. Fuel cells using other fuels and catalysts are still far down the pike.

Methane fuel cells have an electricity-heat ratio close to that of gas-fired diesels. In addition, they are quiet and don't pollute. Methane fuel cells are very close to commercial use. Small demonstration power plants are now in operation. DOE expects that they will be competitive with diesel generators, and that methane-based fuel-cell generating systems will be on the market in about five years. The limited supply of platinum might restrict the availability of these fuel cells, however.

If you are interested in a gas-fired diesel or gas turbine system, you might consider being a pioneer and installing fuel cells. They have similar electricity-heat ratios, use the same fuel, and promise other advantages. Check with DOE; they might be interested in a cost-sharing demonstration of fuel-cell cogeneration.

Fluidized Bed Combustion

Fluidized bed combustion is a new method of combustion rather than a new generating system. Pulverized coal burns in a bed of finely crushed limestone. A continuous flow of air or combustion gases keeps the limestone particles in motion. This is a comparatively clean way of burning coal. The lower combustion temperatures minimize production of nitrogen oxides (NO_x), and the limestone bed permits immediate chemical capture of the sulphur, which otherwise would be released as sulphur dioxide (SO_2).

There are two basic fluidized bed combustion systems, in different stages of development. One works at atmospheric pressure in the furnace and is just coming onto the market. It can power a steam turbine. Its main problem is that the beds are large, so that the system is likely to be expensive for the small steam turbine instal-

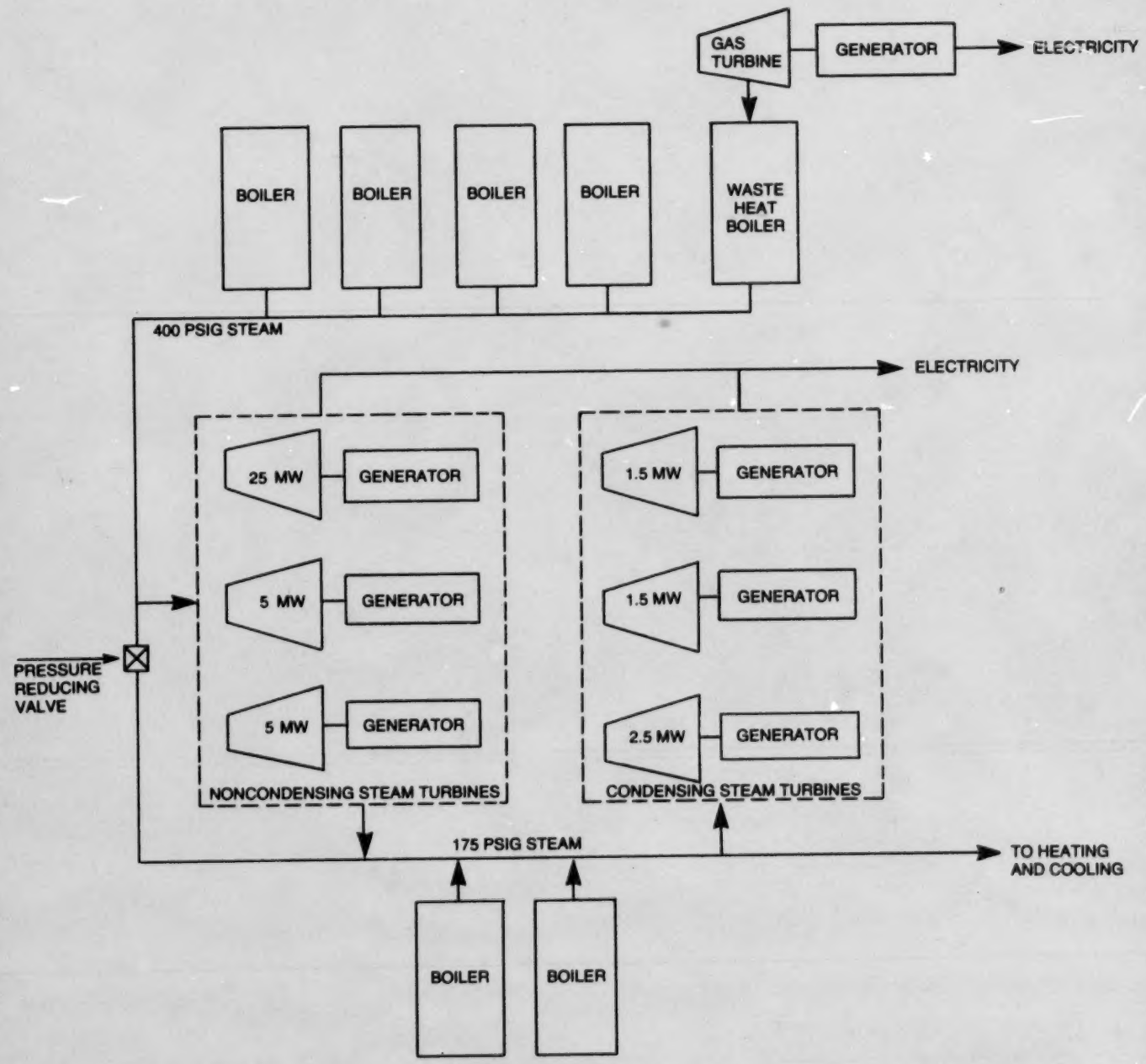

FIGURE 7. University of Texas Combined Gas and Steam Turbine Cogeneration System

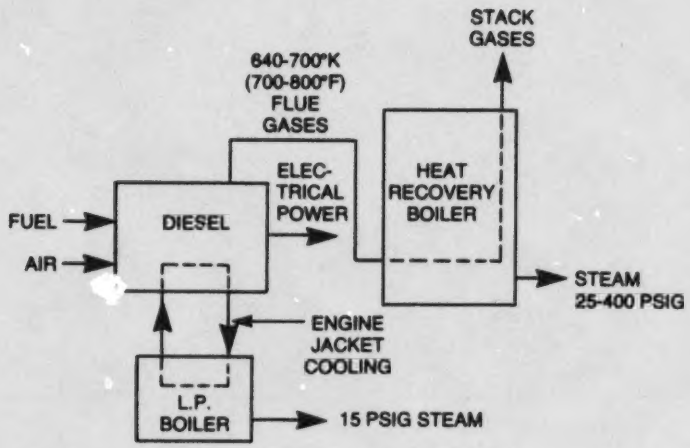

FIGURE 8. Diesel Cogeneration System

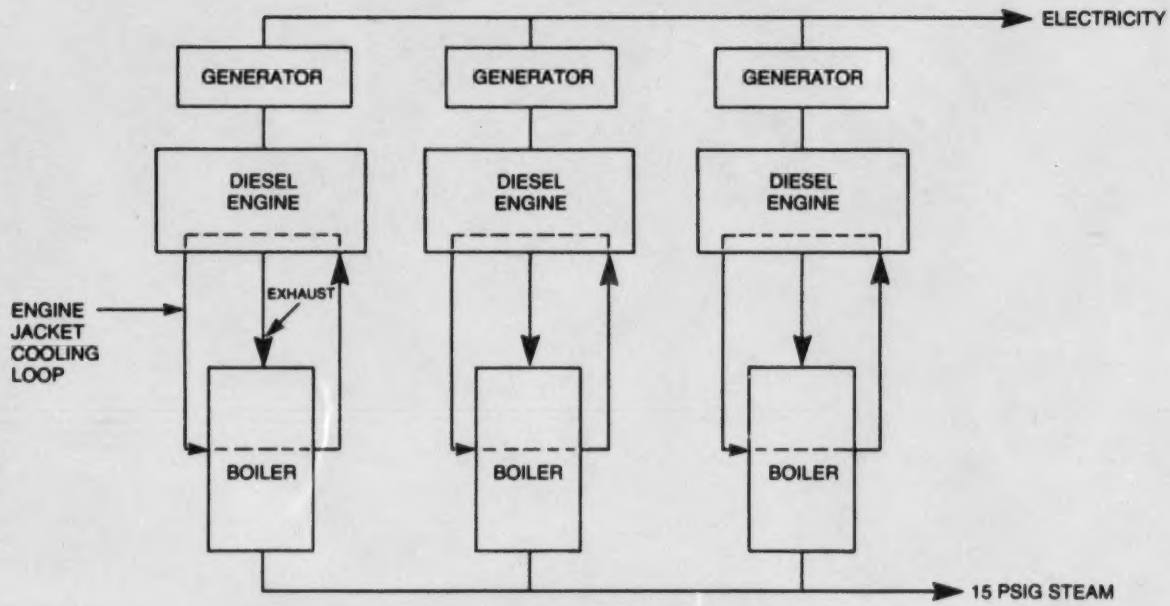

FIGURE 9. Three-Diesel Cogeneration System

lation appropriate for a university. This may, however, be the only choice for a campus wanting to burn coal in an urban environment.

Georgetown University, Washington, D.C., has recently installed an atmospheric pressure fluidized bed boiler system with a rated output of 100,000 pounds of steam per hour. The university is considering adding a steam turbine to make a cogeneration system.

The other fluidized bed boiler system works at four to ten furnace atmospheres of pressure. It will not be on the market for about ten years. When it does, it will be able either to supplement a gas turbine combustion system or to power a gas turbine with its exhaust gases. It produces more electricity than the atmospheric pressure system and is smaller, so cheaper and better suited to small-scale use.

TABLE B
Typical Properties of Cogeneration Systems

System	Sizes (in mw)	Fuel	Electrical Efficiency*	Thermal Efficiency	Elec/Thermal Ratio	Advantages	Disadvantages
Noncondensing steam turbine	1-1200	oil, coal, gas, wood, waste	15%	70%	0.2	Flexibility in fuel	Low electrical efficiency (in smaller sizes), unsuited to small systems
Gas turbine	1-100	#2 oil #6 oil (treated) gas	25%	50%	0.5	Good efficiency, requires less space	Special maintenance requirements
Diesel (with jacket heat recovery)	0.3-30	#2 oil #6 oil (treated) gas	35%	35%	1.0	Best for small systems, high electrical efficiency	High Nitrogen Oxide emission, jacket heat is wasted if there is no need for hot water or low pressure steam
Diesel (without jacket heat recovery)	0.3-30	#2 oil #6 oil (treated) gas	35%	25%	1.4		

*Measures electricity output per fuel input, not taking into account what happens to the heat.

Cogeneration and the National Energy Picture

Oil and gas are in limited supply, and we depend heavily on them because they are convenient to transport and store and are relatively clean fuels. Our dependence makes us politically vulnerable, since a large percentage of our oil is imported.

U.S. energy policy, as defined by the National Energy Act of 1978 and the Carter Administration proposals, responding to the situation, has three goals: (1) coal conversion, shifting from oil and gas to fuels we have large (though not limitless) native reserves of, like coal, oil shale, and tar sands; (2) renewable resource development, encouraging research and development in technologies for using renewable resources like solar energy and wind power; (3) conservation, encouraging fuel use efficiency.

How does cogeneration fit into the national energy policy? It depends on the cogeneration technology and the energy policy goal. Coal conversion (goal 1): the only current option using coal is steam turbines. Gas turbines and diesels still burn only oil or gas and so go against goal 1.

Renewable resource development (goal 2): current cogeneration technology helps only indirectly. Renewable resource technologies are still far from commercial viability. Some of the new power systems, such as wind power and photovoltaic solar, have to be connected to the power grid. Cogeneration systems offer a chance to get experience now, integrating small dispersed power generators with the grid.

Conservation (goal 3): all cogeneration systems improve fuel efficiency, but, as shown in Figure 10 (p. 14), small noncondensing steam turbines produce less electricity per fuel input, so they improve overall fuel efficiency somewhat less than do gas turbines and diesels. The smaller steam turbines appropriate for all but the largest campuses are less fuel efficient than larger ones.

The main problem with fitting cogeneration to the national energy goals, then, is that gas turbines and diesels help goal 3 but hurt goal 1, while steam turbines help goal 1 but do less for goal 3. The goals of coal conversion and conservation can be in real conflict. For example, a small or medium-sized campus may have to make a trade-off. If it converts to coal, it pays less for fuel but can't cogenerate efficiently, since it can only use a small steam turbine. If it cogenerates efficiently, with a diesel or gas turbine, it has to burn expensive oil or gas.

The National Energy Act recognizes this conflict by providing for exemptions from coal conversion requirements for cogeneration facilities.

On balance, such exemptions seem justified.[9] Fuel savings are significant with gas turbines and diesels, and this is particularly important where coal conver-

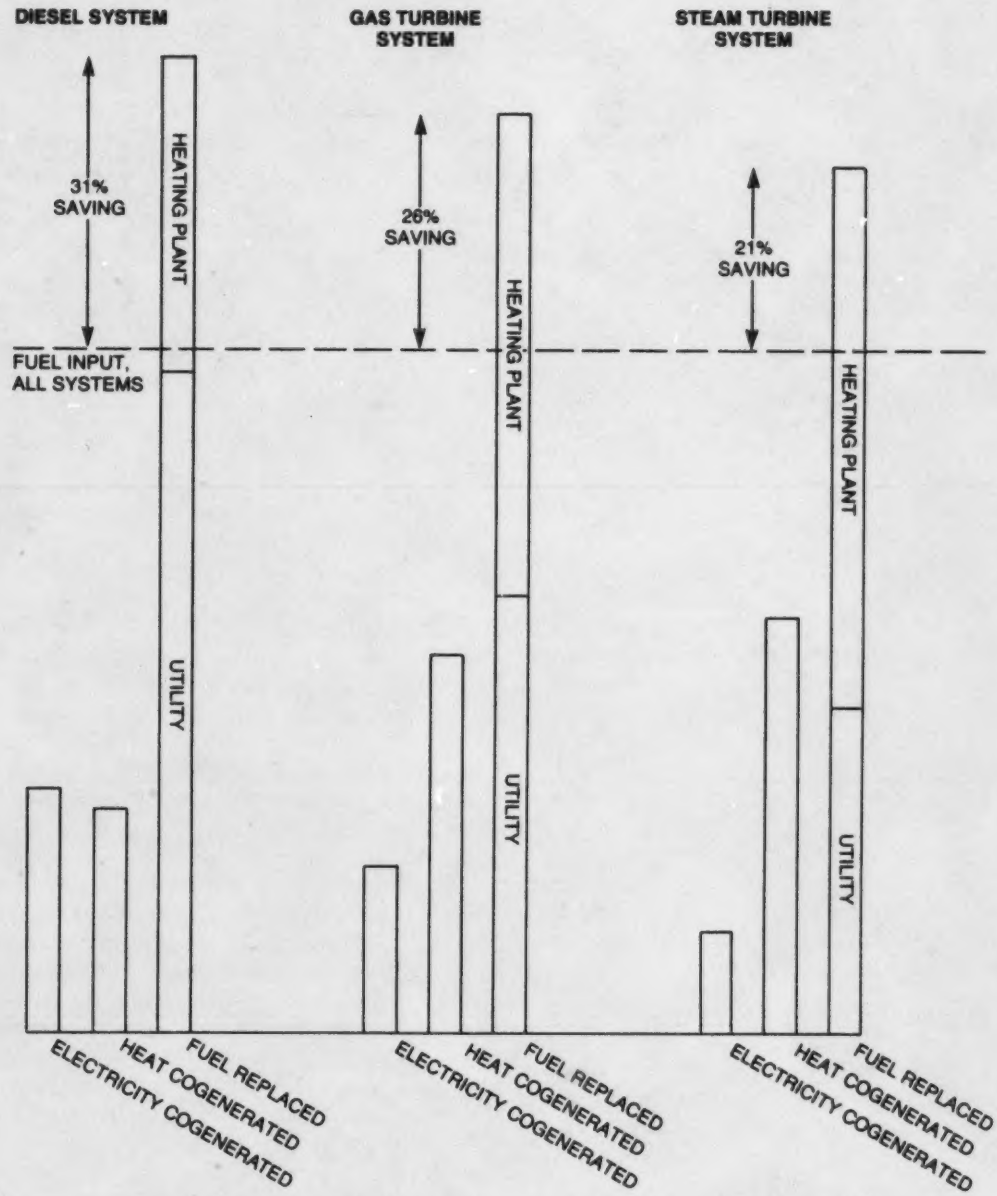

FIGURE 10. Fuel Savings for Representative Cogeneration Systems

sion is impossible. In some areas the serious environmental effects of burning coal may preclude coal conversion. In some areas, particularly the Northeast, even the utilities burn oil and gas, and coal conversion is not yet feasible. This makes conservation that much more urgent, as a temporary stopgap, at least.

Furthermore, present oil and gas-fired cogeneration plants may make future coal conversion easier. Four coal-burning cogeneration technologies of the future, namely pressurized fluidized beds, Stirling engines, coal-fired diesels, and fuel cells, have electricity-heat ratios like those of current diesels and gas turbines. Those technologies will be more acceptable to institutions and industries already experienced with and equipped for such ratios.

Finally, as noted above, the experience of integrating small plants with the utility grid is likely to pay dividends when advanced coal-burning cogeneration facilities and renewable resource generators come on the market.

CHAPTER 2

Conducting a Campus Needs Analysis

Establishing Short-Range and Long-Range Goals

First Considerations

A campus energy management program's primary goal must be to provide the most reliable service with the least expense in money and fuel. How does a cogeneration system measure up? It can save you fuel and money, and it can help you deliver heat and electricity more reliably to your campus. It can even give you some flexibility in choosing the right mix of electrically and thermally driven equipment.

But these advantages require a commitment. Whatever decision you make, you will have to choose a particular energy strategy, and you will have to plan around it for the twenty or more year life of your plant. If you decide on cogeneration, you will have to make some choices and eliminate others. You will have an intricate piece of equipment which restricts the services you can offer in some ways while it improves them in others.

The following points should be given serious consideration. Many boiler systems are quite flexible and can use the cheapest or most easily available fuel. If you cogenerate, you may have to give up that option. A steam turbine will allow you a choice of fuels, but gas turbines or diesels usually will not. Therefore, to make the best possible use of cogeneration's advantages, you have to choose your system very carefully to fit with your present system and future plans. You have to know what services you need to provide and under what economic conditions.

You have to think carefully about the size of your facility. A cogeneration system, unlike a simple boiler system, makes you pay a big premium for oversizing. Therefore, if you want cogeneration, you have to have a good idea of what your energy demands will be. This means that you have to make a thorough analysis of present and future energy needs on campus, and that, in turn, means being ready to invest money for the analysis and working closely with whoever does overall policy planning for your school.

The initial investment should not be a big problem. Your school may already be running a conservation program; most schools are, these days. You probably shouldn't even be thinking about cogeneration if you haven't already had a conservation program for at least two years. If you have, you already have most of the data you will need to analyze your present energy demand pattern. If you haven't, but start now with conservation in mind, you will still save money, because a reasonably strenuous conservation program will cut energy use 25 to 50 percent — an enormous benefit whether or not you decide to cogenerate.

Preliminary Energy and Financial Analysis

The first step toward cogeneration is simple and cheap and can tell you quickly if the idea is unfeasible. You need to make a brief preliminary analysis. What do you need to know and how do you go about finding it out? Ideally, you want an energy profile that tells you what your campus usage is as a function of season, time of day, and occupation pattern. Of course this information is not usually directly available, but you can make a reasonable preliminary analysis based on what information is available.

The first items to check are fuel and electricity bills. These will give you your monthly energy use and a rough profile of seasonal variation. You do have to take account of the difference between fuel consumed and actual energy delivered. But efficiency measurements are part of the regular inspection of your boiler system, so you will be able to make that calculation without too much trouble.

You also have to think about financing. The main justification for cogenerating is that it saves money. It saves money because it uses fuel more efficiently. But you can only find out if it will save you money by an analysis that takes account of such matters as cost of new equipment, costs of fuel and electricity, and the particular circumstances of your institution.

Even if your preliminary analysis shows that cogeneration can save you a lot of money, you may find that it is not feasible. A cogeneration system is a capital investment. It saves on fuel and operating costs and therefore acts as a hedge against rising fuel costs. But whether it is appropriate to make such an investment depends on the financial state of your institution. Private schools may already be enough in debt or they may find it hard to raise capital for other reasons. Public schools are funded through state legislatures and may run into the problem that it is hard to appropriate money for capital investments, even very good, energy-saving ones, while it is less difficult to get appropriations for current operating costs.

Detailed Energy Needs Analysis

Your preliminary analysis gives you the basic dimensions of your energy use pattern. But when you start designing a system seriously, you will need to know about daily variations as well. You just have to grit your teeth and invest in a set of meters throughout the campus that will tell you your energy demands in the course of an average day and from day to day. As part of a conservation program, the meters can pay for themselves many times over in the first year, and they will give you the information you need about how your campus uses energy right now.

The next question is more complicated. How will your campus use energy in the future? A cogeneration system will last twenty years or more, and a lot can happen in twenty years.

For convenience, you can make your predictions in two categories: (1) changes in use of the facilities; and (2) changes in the physical plant itself. These changes are hard to predict, but they will make a real difference to your future energy use, so you need to consult your planners and consider the future as carefully as you can.

Preliminary Analysis: Rough Guidelines for Determining Whether to Cogenerate

The Information You Need

Before you go much further you want to know if cogeneration is right for your campus. This section tells you how to make an intelligent guess. It requires only that you first take a good look at your recent fuel and electricity bills. Of course the result is only a guess, but it can help you decide whether it is worth making a more detailed evaluation. It can also suggest appropriate systems and system sizes for further consideration.

The idea behind the preliminary analysis is simple. In the absence of detailed information, you start with typical university load curves and some typical properties of cogeneration systems: their electric and thermal efficiencies, labor costs, capital costs/kw, and maintenance costs. Then you look at the prices you pay for fuel and electricity, your annual and monthly fuel use, and your annual electricity use. You include a credit for thermal output and allow for a reasonable return on capital investment. On the basis of all these numbers, you estimate how the cost of cogenerated electricity compares with the price of the electricity you buy. If the former is lower, your school is reasonably likely to profit from cogeneration.

The analysis has been made very simple by summarizing all of the calculations in four graphs, so that all you do is see where your school fits on each one. The assumptions used to draw the graphs are specified in Appendix A.

The information you need is: (1) your annual fuel use in 10^9 Btu (typical conversions are one gallon oil = 1.4×10^5 Btu, 1000 cu. ft. gas = 10^6 Btu, one ton Eastern coal = 25×10^6 Btu, one ton Western coal = 20×10^6 Btu), (2) your annual electricity use in 10^6 kwh, (3) the sum of your lowest three months of fuel use in 10^9 Btu, (4) the price of fuel in \$/10^6 Btu, (5) the average price of electricity in ¢/kwh, and (6) the fuel adjustment charge for your electricity. Use a six-month or one-year average for each of the last three items to avoid fluctuations in their relative prices.

The Analysis

Now that you have collected the necessary information, the analysis itself is very easy. It goes in five stages. At each stage you refer to the appropriate graph, identify the point on the graph corresponding to the properties of your campus, and score the number of points indicated. You then add the points from each stage. The total tells you the likelihood that your campus is suitable for cogenerating. The scale is: less than 5 points = low likelihood, 5 to 7 points = moderate likelihood, greater than 7 points = high likelihood. Because steam turbines have very different properties from gas turbines or diesels, there are two figures for each stage, one for a back-pressure steam turbine analysis and one for a diesel/gas turbine analysis. Try both analyses.

Stage 1. Locate your fuel price and electricity price on Figure 11 and score accordingly. In this stage you make the first approximation to comparing your cogeneration costs with utility prices.

Stage 2. Locate your annual fuel use and annual electricity use on Figure 12 and score. This stage takes

account of the dependence of capital costs on size and of the balance between your annual heat and electricity usage.

Stage 3. Be careful here. The variables are different for the steam turbine figure and the diesel/gas turbine figure. In each case you locate the sum of your lowest three months of fuel use, but in the steam turbine case you combine it with the annual fuel use, while in the diesel/gas turbine case you combine it with annual electricity. As before, in each case you score according to the appropriate graph, Figure 13. This stage takes account of gross deviations from the assumed load curves.

Stage 4. Locate your utility's fuel adjustment charge and your fuel price on Figure 14 and score. This stage

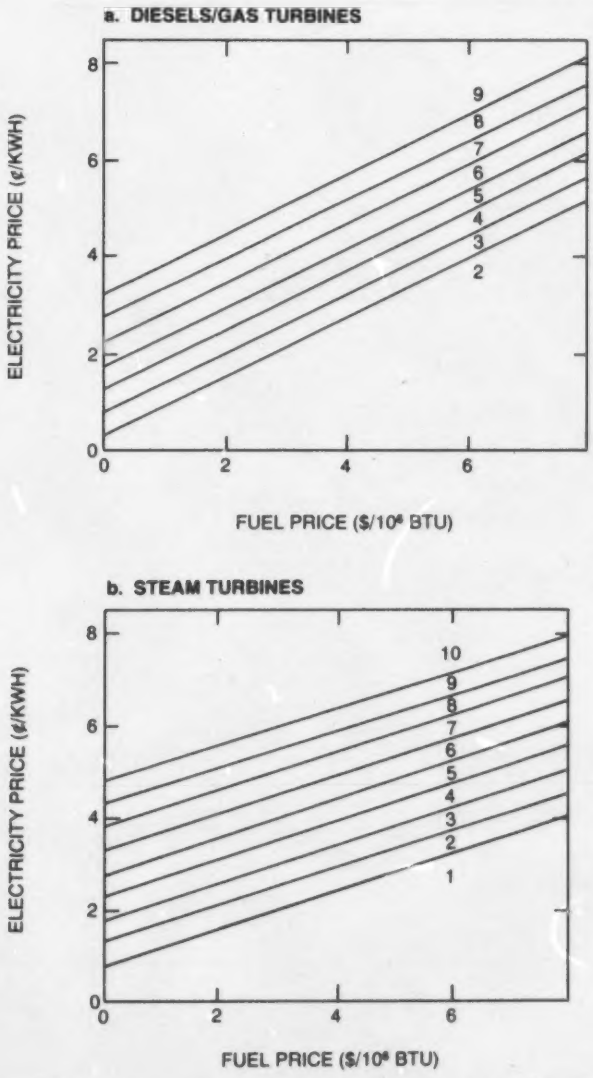

FIGURE 11. Stage One Analysis: Heat vs. Electricity Prices

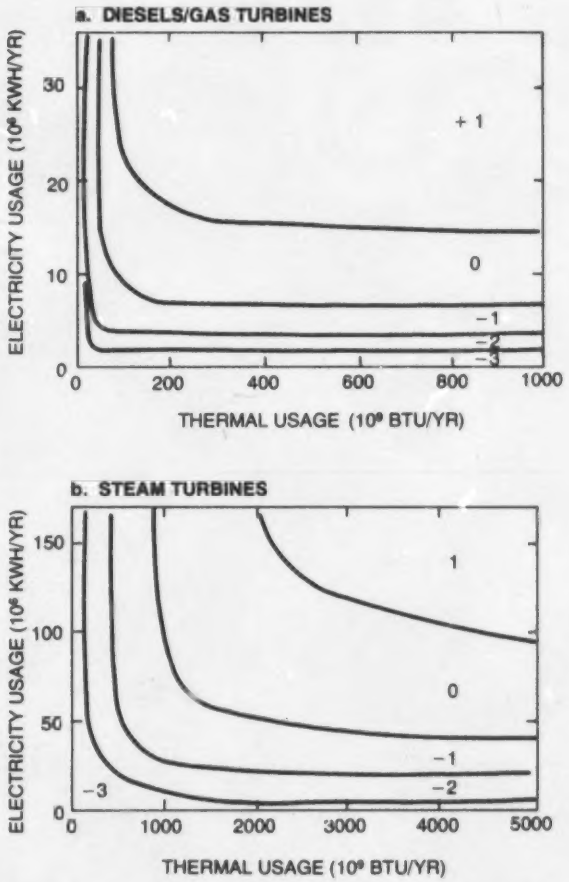

FIGURE 12. Stage Two Analysis: Heat vs. Electricity Annual Use

makes a simple comparison between your utility's fuel expenses and yours.

Stage 5. Check through these miscellaneous items: (1) Are you about to replace your boiler system? Add one point. (2) Are you about to replace your distribution system? Add one point. (3) Do you have a hot water distribution system? Add one point. (4) Are you in an area with poor air quality? Subtract one point. With notoriously poor air quality? Subtract two points. (5) Are you now burning coal but considering diesels or gas turbines? Subtract one point.

Find your total score and determine the likelihood for your campus. To illustrate the procedures, a sample analysis for Clark University is shown in Table C.

Conclusions

By making the analysis, you estimate how suitable cogeneration is for your campus. By making both analyses, you see whether you are primarily interested

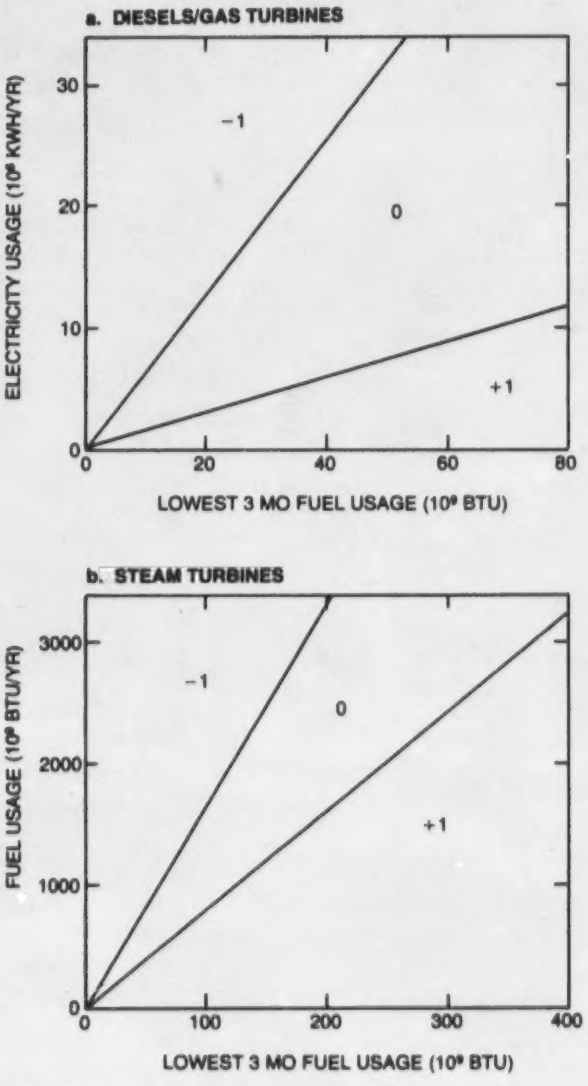

FIGURE 13. Stage Three Analysis: Minimum Fuel vs. Annual Electricity or Fuel Use

in steam turbines or in gas turbines and diesels, or whether you should look carefully at both.

The analysis assumes that you are interested in diesels or gas turbines with an electrical output somewhere between your peak and your average demand and in steam turbines with a heat output near your average thermal demand. It also assumes that you will be modifying an existing system, so backup heating equipment will be available, but that new space and system modifications will be expensive. If you are planning a totally new plant, you will need to meet all thermal demands; the effective capital costs, however, will be lower. These provide good starting points for trying systems. If you go on to a conceptual design you should test both larger and smaller systems to identify the most appropriate size. In all cases electrical capacity greater than your peak electrical demand can only be justified if you have negotiated good terms for electricity sales.

Certain rules of thumb follow from the figures. (1) High electricity prices (see Figure 11) encourage cogeneration, so you are much more likely to want to cogenerate in the Northeast than in the Northwest.

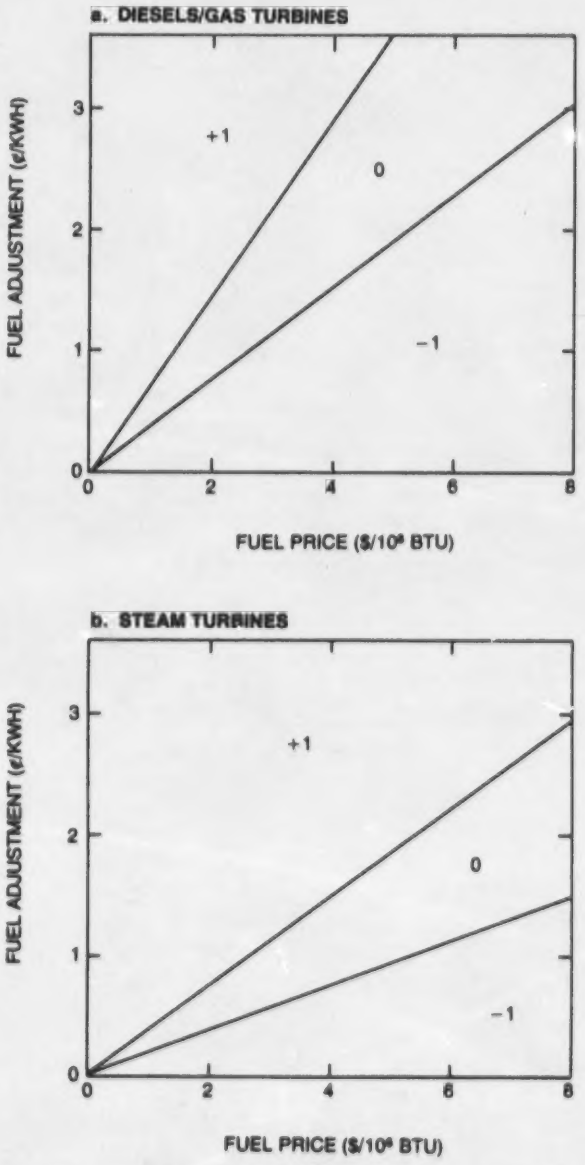

FIGURE 14. Stage Four Analysis: Utility Fuel Adjustment Charge vs. Fuel Price

TABLE C
Clark Estimate of Cogeneration Likelihood

Information (September 1979)

1. Annual fuel use	140×10^9 Btu/yr
2. Annual electricity use	7×10^8 kwh/yr
3. Three-month minimum fuel demand	10×10^9 Btu
4. Fuel price (#6 oil)	\$4.00/10^6 Btu
5. Electricity price	5¢/kwh
6. Fuel adjustment charge	2.9¢/kwh

	Diesel	Steam Turbine
Stage 1: Figure 11	7	6
Stage 2: Figure 12	−1	−3
Stage 3: Figure 13	0	0
Stage 4: Figure 14	1	1
Stage 5: Poor air quality	−1	−1
TOTAL	6	3
	Moderately High Likelihood	Low Likelihood

(2) If your annual fuel demand is significantly lower than $1{,}000 \times 10^9$ Btu/year, chances are that steam turbines will not be economical (see Figure 12). (3) If your annual electricity demand is much lower than 2×10^8 kwh/year, chances are that no system will be economical (see Figure 12).

Identifying Technical Parameters of a Basic System

General Considerations

The last section showed how, using your fuel bills and easily available facts about your physical plant, you can decide if cogeneration is likely to be a good choice for your campus. If you think it might be, and decide to do a full-fledged feasibility study, the next steps are to consider all of the facilities you might want to service and to collect detailed information on your total physical plant and its energy demands.

You need to think about the possibilities for servicing other facilities because the size and demand mix of the total system are important to your choice of cogeneration system. You need detailed information on your physical plant because your cogeneration system will be integrated with the existing distribution system and end-use equipment, and possibly with the present power plant as well. What you now have will in part determine your cogeneration options. You need detailed information on your energy demands because they also help determine your cogeneration options. Cogenerating equipment produces both heat and electricity, and its performance is quite sensitive to demand. Therefore, to make the best choice of a system, you need to know how heat and electricity demands vary, separately and together.

A technical study will cost you some money. There are ways you can cut the costs, however.

You can involve faculty and students. Physics, engineering, applied science, and energy and environment faculty are always looking for practical projects for their students. Studies of heat and electricity use on campus, of alternative energy sources and uses, and of economic feasibility make attractive projects. Not only can this save you hours and manpower, but you might be able to charge some of the necessary meters to the academic budget.

You can integrate the study with your other conservation plans. Detailed measurements of energy use will pinpoint waste in the system and therefore can be very helpful for conservation.

You can take advantage of the National Energy Conservation Policy Act of 1978, Public Law 95-619 (NECPA). It awards matching grants for energy audits. The money is to be administered by the states, and therefore the provisions will vary, but in general the federal government will pay up to half the costs of the audit. If you are not already making such an audit, sample audit procedures are listed in an Energy Task Force publication.[10]

Servicing Other Facilities

It is worth finding out about other facilities you might want to service with your cogeneration plant. A bigger plant brings economies of scale and can therefore look financially attractive. There are some problems, however.

You need to find customers for your extra output. Usually those will be facilities nearby with whom you have good relations. You will have to negotiate terms and prices, promise and produce a given reliability of delivery, and settle all legal and regulatory problems.

If you build for extra thermal capacity, your customer has to be a large user like a hospital or office complex adjacent to your campus. Otherwise, installing new thermal distribution lines will be prohibitively expensive. You also have to worry about jeopardizing your nonprofit status by selling heat. Check with your lawyers, especially about tax and zoning, and see what is possible. The University of Minnesota has successfully negotiated such an arrangement. It plans to sell excess steam from its cogeneration plant to two neighboring hospitals and a nearby college.[11]

If you build for extra electric generating capacity, your transmission problem is smaller, but the legal problems are much greater. You have the same prob-

lems with your nonprofit status, and you also run into utility monopoly privileges. You may be able to negotiate cooperative ownership of the plant, either with the utility or with the other facility. Or maybe you can persuade your utility to buy your extra electricity on favorable terms. Opportunities are limited, but your school may be the one that has them. In any case, check the law carefully.

If you think you might go this route you will have to include the other facilities to be serviced in your needs analysis and you will have to solve formidable problems, both in negotiating terms and in meeting legal restrictions.

Physical Plant Description

Once you have made a preliminary decision about the total physical plant you intend to service, you need to identify its heat and electrical needs and other relevant considerations in detail. Here are points to consider:

Campus. (1) Location: where is your campus? Is it urban? Rural? Do you have neighbors who might be disturbed by increased noise of fuel deliveries? What is its topography? Will it be able to disperse added air pollutants? Can neighborhood traffic patterns handle additional fuel deliveries? (2) Layout: are the buildings spread out or compact? Where is the central heating plant? Is there space to add to or modify the heating plant, including fuel storage facilities? Can campus traffic patterns handle additional fuel deliveries? How much of a mess and bother will construction produce? Can you dig to make changes in the distribution system?

Heating plant. (1) Boilers: how many are there? Size? Capacity? Operating pressure? (2) Fuels and fuel handling: if you use coal, how do you handle it? If you use oil, what kinds of storage and warming facilities do you have? If you use gas, what is the size of your gas line?

Distribution system. (1) Operating medium: do you use steam, hot water, or a mix? What is your steam pressure? What is your hot water operating temperature? (2) Physical plant: what sizes of lines do you have? Can you modify them easily (for example, could you run your steam at a lower temperature and consequent lower pressure)?

End use equipment. (1) Heat-electricity balance: can you use your heat at lower temperatures to squeeze more electricity out of the system? For instance, can your radiators be adjusted to work at lower temperatures or pressures and still provide enough heat? (2) Seasonal constancy: can you make the heat-electricity balance as constant as possible through the year? Can you find opportunities to use more absorption air conditioning and less electric air conditioning? Are there places where it would be useful to install supplementary heat pumps?

Future changes. (1) Use: is your school starting or dropping summer sessions? Instituting a month-long winter break? Do you expect growing or shrinking enrollment? How much? Over what period? Can you institute acceptable conservation measures in temperatures, lighting levels, and the like? (2) Physical plant: is the campus growing or shrinking? Are you adding or subtracting buildings? How will you meet their energy needs? Are you changing the functions or energy-using equipment of buildings? Are you installing conservation equipment: insulation, storm windows, a boiler economizer, a control system? (3) Fuel: are you planning to convert to different fuel, wholly or in part? Are you assured an adequate supply of fuel for your campus needs at the present rate? Are you assured an adequate fuel supply if you decide to cogenerate?

Energy Load Requirements

To choose cogenerating equipment of the right size and to make an economic analysis of it, you have to know your school's heat and electricity steady loads and peak demands in some detail. You have to know how each varies with time and how they are correlated. You need both actual and "typical year" data. Also you need educated guesses about how planned changes in physical plant and use patterns will affect demand.

How do you get such information? You install meters, read them, and interpret the results. For electricity demand it is most convenient to have a recording electrical meter. Your school may already use one. Because electricity consumption depends far more on campus use pattern (the pattern of day-to-day building use on campus) than on season, it is relatively consistent. So you can usually make do with hourly readings on a smallish number of typical days (summer and winter, weekdays and weekends, sessions and vacations). If you heat or cool with electricity, however, there may be significant seasonal dependence, and you will have to collect more data.

For heat demands, you need meters for your boiler system, either in the steam line or in the condensate return line. Again, recording meters are most convenient. Though heat use, like electricity use, shows a typical diurnal and campus use pattern variation, it also varies a lot with season. You want to find out how much of your heat use depends on outside temperature. Therefore, you need detailed and accurate heat use data. You also need daily records of average outside temperature. You either get these from a local weather station or take them yourself. You may also find it convenient to meter your incoming fuel. This

gives you a direct measure of boiler efficiency under varying thermal demands.

Once you have gathered this data, you want to make an electricity load curve, a thermal load curve, and a correlation of electricity and thermal demand. The electricity load curve is easy. You can practically read it straight from your data. Just plot kilowatts against annual hours at or above that power level. Figure 15 shows a sample electricity load curve from Clark University.

The thermal load curve is harder because of seasonal variation in heat demand. You can record hourly variation in heat use over typical days, summer and winter, sessions and vacations, weekdays and weekends, just as for electricity use. But because outside temperatures directly and critically affect heat use, you have to find out just how much of your thermal demand depends specifically on outside temperature.

Figure 16 shows a sample correlation of heat use with degree days per day (average number of degrees under 65°F or over 72°F that the temperature is on a given day) for the heating season at Clark University. At 0 degree days (outside temperature 65°F), when there is presumably no need for space heating, Clark uses 120 million Btu per day.

You can construct one of these for your own heating season, and another for your cooling season. Then, based on historical weather data for your region, which will tell you the expected number of days per year when the mean temperature is less than 0°F, 0-10°F, 10-20°F, etc., you can predict how many days would have a demand greater than 120×10^6 Btu, 240×10^6 Btu, and so forth. This provides you with a thermal load curve giving heat use by the day. To convert it to an hourly curve, you need an analysis of how heat use varies through a typical day. This shape usually depends on campus use rather than tempera-

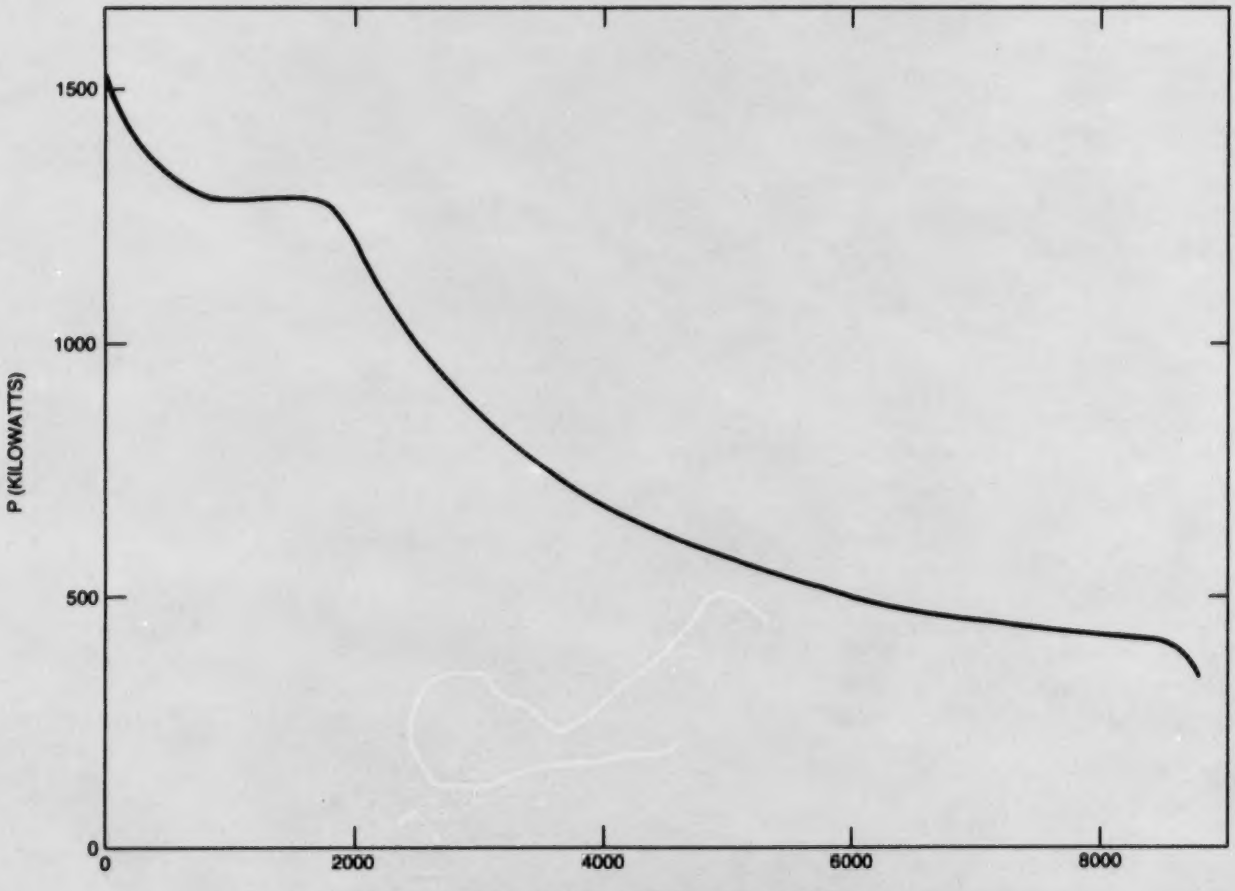

FIGURE 15. Clark University Electric Load Distribution

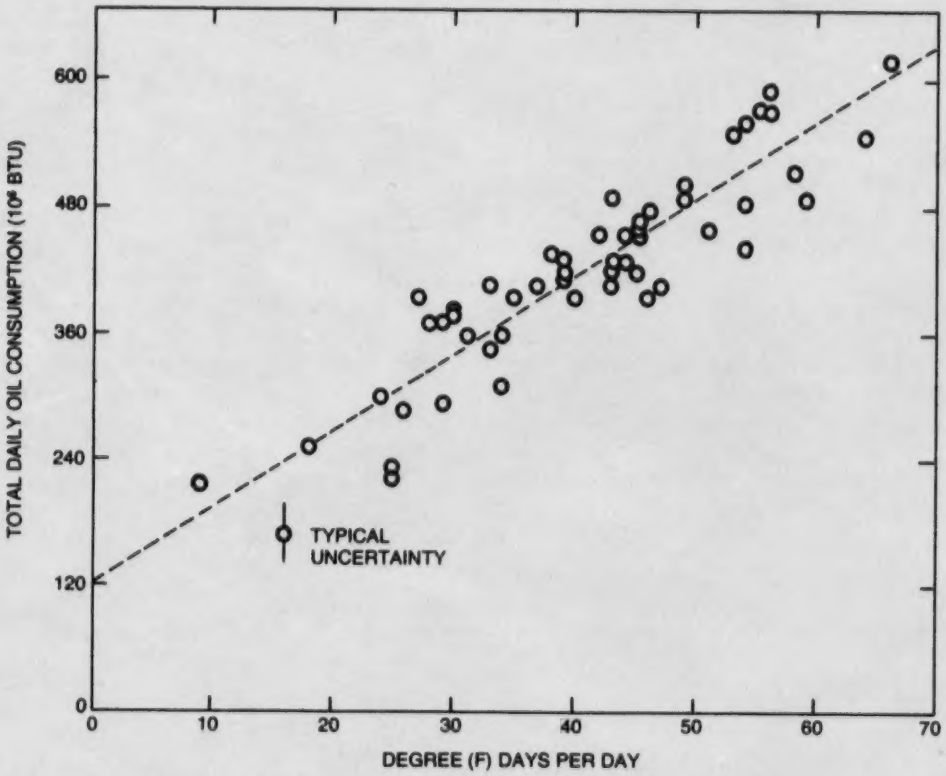

FIGURE 16. Clark University Heat Use as a Function of Degree Days

ture. With the diurnal shape and the daily thermal load curve, you can construct an hourly thermal load curve. Figures 17 and 18 (page 24) show sample thermal load curves from Clark University and the University of Minnesota.

Don't treat your curve as a perfect predictor. It is general, only as good as it has to be to give you reasonable choice in evaluating cogenerating systems. In particular, it does not allow for weather variations from year to year. Therefore your evaluations should anticipate about a 10 percent uncertainty spread around the points on the correlation curve. You have to allow for the atypical winters as well as typical ones.

In addition to making independent electrical and thermal load curves, you may well have to make correlations of the two. The kinds of correlations you need and the form you need them in depend on your arrangements with your utility and on the size and type of plant you are thinking about.

Cogeneration and Planning for the Future

As you make your energy needs analysis, think ahead. What will your needs be in the future? What changes can you predict in your institution and other facilities that you service over the twenty-year life of your cogeneration plant? You will have to adjust your load curves for the demands of new facilities and changes in use and servicing of old facilities. If you have to air-condition an old building for expanded summer use or build a new one, for example, allow for it in your plans. Your experience with similar buildings and the best information you can get on size and construction of projected buildings will help you make educated guesses.

Some of the physical plant changes that your school may be expecting in the next twenty years or so are best planned in conjunction with a new cogeneration system, as they affect your options. For practically any college or university, you won't be starting from scratch. Your cogeneration system will be integrated with the existing plant. You can reduce overall costs and trouble if you integrate your planning as well. Will you need to replace or add a boiler or parts of your distribution system? To expand your system? Those are good times to cogenerate. Are you considering other major equipment changes or a switch in fuels? Be sure to plan overall, so as not to lock out any possible advantages before you have to.

It pays to think of the end services, not just of how to provide them. This is because you can often find ways

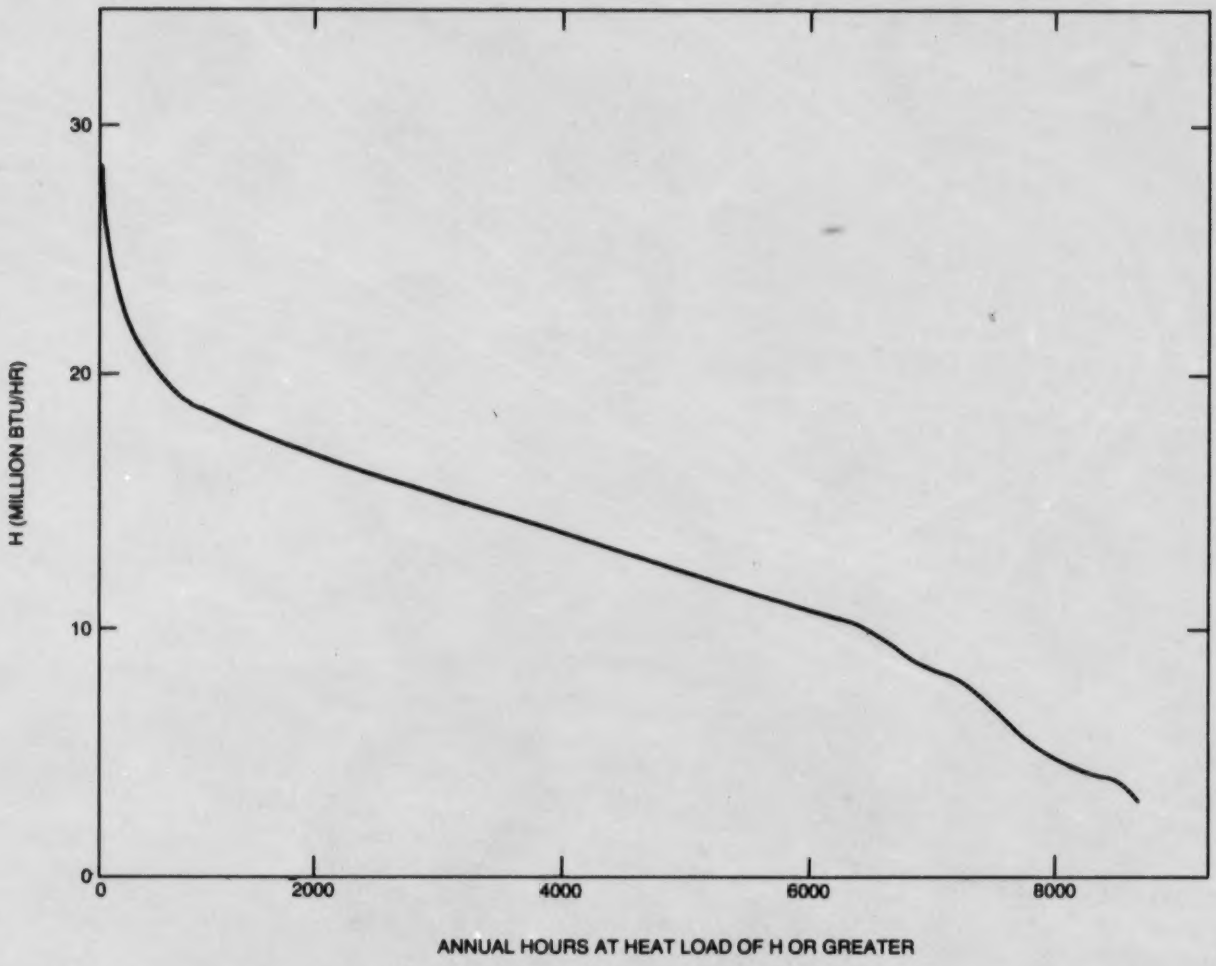

FIGURE 17. Clark University Thermal Load Distribution

to adjust the mix of thermal and electric energy use and thus improve the efficiency of your cogeneration system. The basic services are space heating and cooling, ventilation, domestic hot water, lighting, cooking, and equipment. Some, like space heating and cooling, allow you to use a system driven either by electricity (heat pumps, electric air conditioners, resistance heaters) or by steam or hot water (absorption air conditioning, steam or hot water radiators). As you plan to build or renovate, you can plan to provide energy services in the form that makes the best use of your cogenerating system.

Once you have settled the technical parameters of your plant and calculated present and future energy load requirements, you can begin to develop a conceptual design for your cogeneration plant.

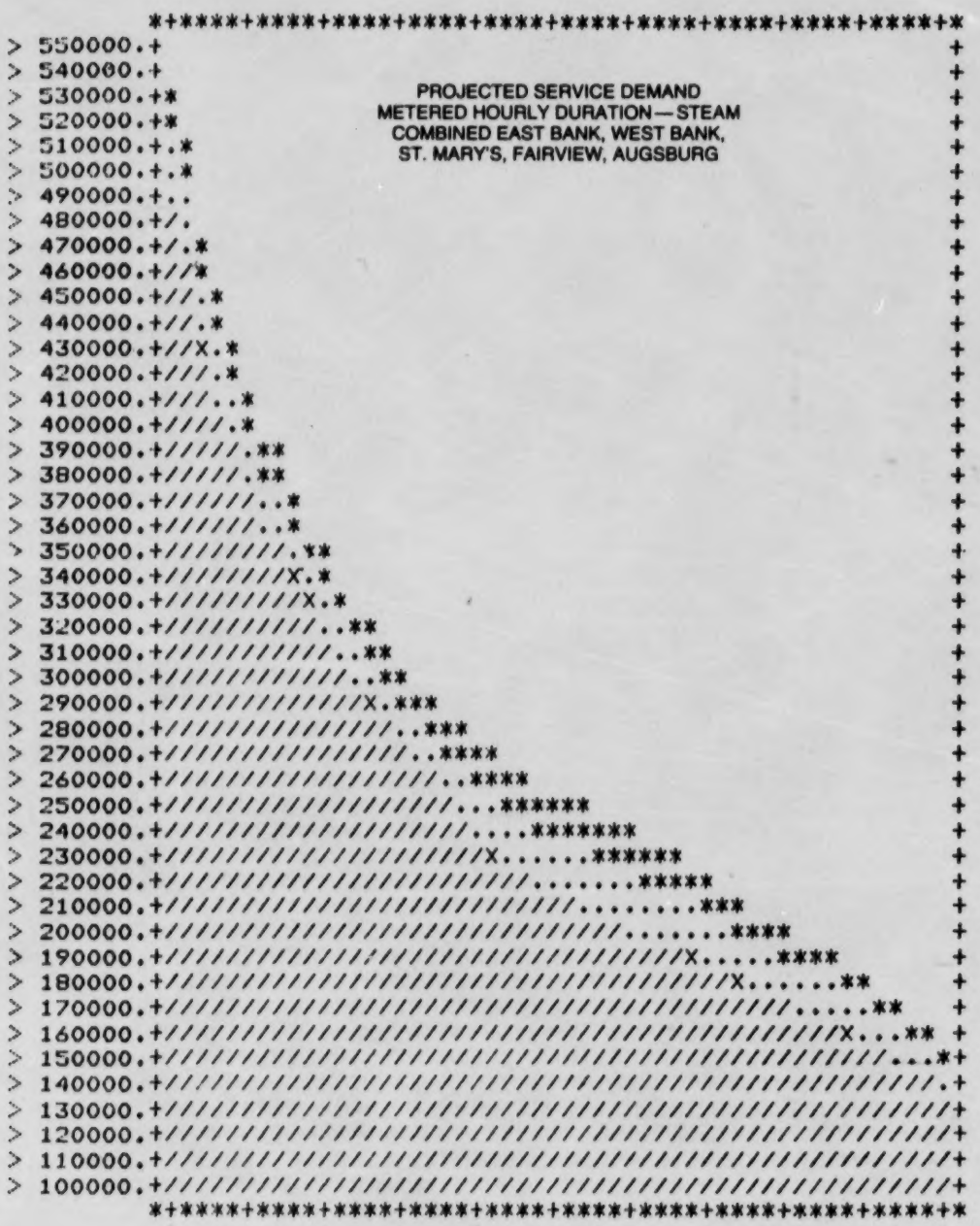

Figure taken from *Grid-Connected Community Energy System, Executive Summary.* Final Report. Phase I. June 1977. University of Minnesota.

FIGURE 18. University of Minnesota Thermal Load Distribution

CHAPTER 3

Steps to a Conceptual Design

From Needs Analysis to Conceptual Design

The conceptual design stage requires you to do several things simultaneously. Your goal is to make a conceptual design for your cogeneration facility, that is, to decide on the basic type of facility, to make specifications for the major equipment, and to determine space needs and operating and maintenance requirements. To do this you have to work closely with your utility company, negotiating your connection with the power grid. You have to prepare to work for community acceptance of your plant. You have to make sure your plans comply with many legal restraints and requirements on every governmental level and you have to think about getting the necessary official permits when you've completed the planning requirements. Finally, you have to select and design the system that is best and most economical for you.

Most of these things have to be done together. For example, your choice of equipment may be limited by environmental constraints, so you have to find out what air quality regulations apply before you decide. But different sizes and sorts of equipment have different regulations, so you have to choose before you can know which laws apply. You have to work with the environmental quality people while your equipment decision gradually evolves.

Similarly, before the utility company can offer you rates and terms, they will want to know the specific details of the equipment you are installing so they can calculate your effect on their system. But your choice of equipment depends crucially on what terms you can negotiate with them, whether you can sell electricity, under what rates, and whether you provide your own backup. Again, the rates and terms and the final decision have to evolve throughout the process.

Your detailed picture of campus energy needs is the basis for all the activities leading to a conceptual design. The conceptual design in turn is the basis for the economic evaluation that will be a major part of your final decision for or against cogeneration.

Working with the Utility

General Considerations

Very soon after deciding that you are seriously interested in cogeneration, you should talk to your electric utility. But you should realize that utilities have, in the last few decades, systematically discouraged the development of cogeneration. There are reasons. Cogenerating institutions threaten utilities with a loss of revenue; if you are generating your own electricity, you aren't buying theirs. Also, their regulatory structure limits their interest in cogeneration. Utilities are only allowed so much return on their capital investment. This discourages experiments with untried technology. Utilities are allowed to profit only on their capital investment. Therefore, even if you sell your electricity to a utility, it can't include your capital investment in its rate base. It can pass costs through to the buyer, but it can earn no return for its investors.

But times are changing. Power plants are enormously expensive to build. Utilities are having greater difficulty raising capital to build them. Getting the necessary permits is also much harder and slower than it used to be. Environmental regulations are more stringent, awareness of possible undesirable side effects of new plants is greater, and opposing citizens' groups are more active. As a result utilities have to spend ten years or more constructing a new plant. Planning for needed capacity that far in advance is necessary, but risky.

As a result of the high cost and long lead times of new generating capacity and the uncertainty in future demand, regulatory agencies are trying to encourage new ways of meeting electricity demand, including cogeneration. For the most important of these, the very recent Public Utility Regulatory Policy Act, see the next section. This set of regulations will certainly make contracts with utilities more feasible and favorable. But because it is so new, no practical experience with it exists, and we can't say exactly how it will affect either contracts or utility attitudes.

The producers of electricity are responding both to changing attitudes of regulatory agencies and to their own recognition of changing conditions. Many utilities are moving toward toleration of and accommodation to cogeneration. A few are even encouraging its development.

Whatever your utility's position, you should get discussions going as early as possible for several reasons. First, it is a matter of simple courtesy. Unless you are a very small college dealing with a very large utility, your decision to cogenerate could have a noticeable effect on the utility's loads, and the utility will want to know as soon as possible.

Second, your utility, like many others, may be reevaluating its cogeneration policy. Utilities move very slowly and ponderously, so the more time you give it to work things out, the better your chances that what it works out will be reasonable, and that it will be done in time to benefit you.

Third, the more time you have to talk, the better chance you have to make reasonable terms. This can make a big difference in how reliably and economically you can meet your energy management goals.

Fourth, the terms you make may critically affect your choice of system. For example, you will need to know whether you have to provide your own backup or not and what alternatives you have for using the electricity you produce. You can't choose a size or type of system until you know these things, and the sooner you get started on negotiations, the sooner you'll know.

Public Utility Regulatory Policy Act

The most important recent change in regulation has been the passage of the Public Utility Regulatory Policy Act (PURPA), part of the National Energy Act, in 1978, and the FERC regulations for implementing it which have just been published (February 25 and March 20, 1980).[6,7] The act requires public utilities to provide complete cost information on their operations, including plans for expansion. It requires utilities to purchase electricity from qualifying cogenerators and small power producers at rates reflecting the utilities' avoided costs. It requires the utility to operate in parallel with qualifying facilities if they request it, so that the utility purchases only electricity in excess of the facility's demand. It requires the utility to provide backup or supplementary power at nondiscriminating rates. It requires utilities to wheel (transfer) power to other utilities at fair rates at the request of the qualifying facility. It exempts qualifying facilities from most provisions of the Federal Power Act, from the Public Utility Holding Company Act (in particular, a qualifying facility is not to be considered an electric utility company), and from state laws regulating public utilities. It allows for the exemption of qualifying facilities from the incremental tax pricing provisions of the Natural Gas Policy Act of 1978.

A qualifying cogeneration facility is defined as one in which not more that 50 percent of the equity in the facility is owned by a public utility, which is less than 80 mw, and in which at least 5 percent of the total energy output is in the form of useful thermal energy.[7] In addition, oil and gas fired facilities must satisfy an efficiency criterion: the useful power output plus half the useful thermal energy output of the facility during any calendar year must be more than 42.5 percent of the energy input of natural gas and oil to the facility. A qualifying cogenerator must furnish FERC with ownership and technical information about the facility. In addition the cogenerator can request certification as a qualifying facility on the basis of this information.

At present, new diesel facilities are not considered qualifying facilities pending an environmental impact statement. FERC plans to rule shortly on the qualification of new diesel facilities. Purchases from cogeneration plants on which construction began before November 9, 1978 don't need to be at the utility's avoided cost if the state regulatory agency decides that this is not necessary to encourage cogeneration.

Technical Considerations

Technical details of the tie to the utility must be settled in negotiations with your utility. You need to add a certain amount of basic equipment to tie your system to the utility. You need meters to measure both electricity coming in and electricity going out. You need relays that will cut you off the grid and protect the utility system if your generator or system fails. Otherwise, your failure might cause a malfunction at the substation and possibly damage the grid. You need relays that will cut off the grid connection and protect you if there is a utility failure somewhere. These serve the double function of preventing damage to your generator from loss of load and preventing your generator from keeping the utility wires hot and hindering repair if a utility line is broken. You need lines and transformers that connect your system to the utility's distribution system. You need an assortment of other connection hardware.

You will almost certainly have to pay for all of this additional equipment. You definitely will if you negotiate your agreement under PURPA. You can, however, probably use the lines and transformers that connect you to the utility's distribution system now.

Agreements Between the Utility and the College or University

Your utility may or may not have a specific policy for cogeneration. Because of PURPA, most utilities will within a year. If yours does, it will have a cogeneration rate structure approved by the state public utility commission. It will tell you the rates, and you can plan accordingly. Remember, however, that the change in the regulatory climate encourages rate changes in favor of the cogenerating customer and you should be watching for them. Furthermore, if you feel that the rate structure is unfair, you can first negotiate with the utility and then appeal to the public utility commission, just as described below.

If your utility does not yet have an approved cogeneration rate structure, it may be willing to work out a special contract with you. This also will have to be approved by the commission. If you and the utility can't agree on a satisfactory arrangement, you can ask the commission to intervene. But it is better to negotiate if at all possible.

There are two kinds of useful arrangements you can make: to buy backup power from the utility, and to sell power to the utility. You might want to buy backup power because all generating systems, even the most reliable, are subject to down time, both for accidents and for maintenance. You can make yourself independent of the utility by having spare generators, but this is an expensive route to take. The excess capacity costs you money and, because it is mostly idle, you won't get a good return on your investment. The utility, on the other hand, can get away with proportionately less standby capability. It can spread that capacity over many generating stations which are statistically unlikely to be down all at the same time. Therefore, it ought to be cheaper for the utility than for you to provide the backup power. Whether you can get a rate that reflects this, though, is another question.

Rates in a typical standby agreement might have any of the following pieces: (1) A charge for the standby connection. This might be a charge per kilowatt of maximum contracted demand, for example. (2) A charge for the amount of electricity bought. This may or may not simply follow one of the utility's regular rates. It can include a demand charge based on peak demand over some previous period and an energy charge for the energy actually bought. It is usually a disadvantage, and may be unfair to the cogenerator, if the demand charge portion is high. Such a structure assumes an ordinary load demand pattern, and that is not what a cogenerator will produce. (3) The fuel adjustment charge, depending on the utility's cost for fuel, automatically passed through to you. Rates may depend on time of day or season.

You might be able to buy backup power much more cheaply on an interruptible basis. If the utility doesn't have to provide you with power when it is overloaded, during a brown-out, for instance, it may offer much lower rates. But you have to be willing, and able, to accept the lower reliability of the system.

The other kind of agreement you might want to make is to sell power to the utility. Your marginal or incremental cost for producing electricity is likely to be lower than the utility's. (If it isn't, you don't want to cogenerate anyway.) Therefore, the sale of your excess power can benefit both you and your utility, since you can split the difference. But you can only do that if you actually negotiate a suitable agreement.

Such an agreement might be harder to negotiate than a standby agreement. Utilities aren't used to buying electricity from small concerns, and power sales contracts are uncommon. Therefore, there is no standard form of.contract to depend on.

There are two basic arrangements you and your utility might consider for your power sales contract. Both are acceptable under PURPA. (1) You sell all your power to the utility and then buy the power you need from the utility at standard rates. This arrangement makes special standby agreements unnecessary. (2) You sell only your excess power to the utility. There may be restrictions on time or season or power level for sales.

In the first arrangement, you are clearly providing additional capacity to the utility. The utility's buying rate should reflect the value of that excess capacity, either as specific capacity credit or as part of the rate per kilowatt-hour.

In the second arrangement it is not so clear that you are adding capacity to the system, unless you can guarantee that your excess will be available at times of peak utility demand, which is unlikely. If you aren't adding capacity, the utility's buying rate should reflect simply the utility's savings in operating costs. In its negotiation with Clark University, for example, the Massachusetts Electric Company has agreed to pay its incremental fuel cost (that is, the amount it saves by turning off its worst generators), including transmission losses.

There is one alternative to your selling either all your power or just your excess to your utility. You might be able to persuade your power company to either assume joint or full ownership of the cogenerating plant. The advantage for the utility is that the plant's capacity can be included in the utility's rate base. The advantages for you are, first, that the utility will either pay for the plant or help raise the money to pay for it, and, second, that the utility will take over all the regulatory headaches (sale of power, grid connection, and so forth).

The possible disadvantages for you are the following: (1) You might prefer to make your own investment because the utility might not be willing to pass on to you your proper share of the savings due to cogenerating. (2) You and your power company would have to live on intimate terms. You would have to work out many areas of conflict, like fair prices and maintenance, so that both parties felt secure.

Negotiating with the Utility

Your best strategy is to approach the utility from the top. If you start at the top, you are much more likely to be taken seriously. You will be directed down to the people in the power company who are responsible for thinking about cogeneration.

In order for you to negotiate the best possible terms with your utility, you have to understand the effect of your cogeneration plant on the system. Whether you sell all your power to the utility and buy what you need at standard rates, or sell only your excess and buy backup power, the effect is exactly the same. You are adding capacity to the utility system. The major portion of your power output comes from meeting the constant part of your thermal demand and acts just like a utility baseload generator, which runs all the time except for servicing. The remaining portion of your power output follows thermal demand. Periods of high thermal demand correlate well with peak electrical demand times for the power company. This is most certainly the case if you are balancing your winter and summer thermal loads by using absorption air conditioning. Therefore, since the nonconstant capacity you are adding follows system needs, it is even more useful for the utility. Further, small cogenerating plants are easier to repair and so should be far more reliable than large utility baseload plants, which run 60 to 70 percent of the time. Therefore, you are also adding a highly reliable system.

Both your ability to match utility demand and your reliability are important bargaining points. A power company unaccustomed to cogeneration may well argue that the electricity you sell is not worth much because it comes at irregular times and in irregular amounts and that the backup electricity you buy is expensive because your demand is sporadic, possibly at peak demand times, or caused by uncontrolled equipment failures. But a typical baseload generator is off irregularly around 30 percent for repairs and maintenance and produces at a flat rate the rest of the time. Your cogeneration plant will probably be able to produce electricity around 90 percent of the time. Your peaks in thermal demand are likely to match utility peaks fairly closely, especially if you use some absorption air conditioning, so your electricity generating curve will tend to smooth out the utility load curve. Your net effect on the system load is actually very good for the utility.

What, then, should your utility pay you for electricity? If you sell all your electricity to the utility, it is clear that you are adding valuable capacity to the system, and they should pay a credit for this capacity as well as cover operating costs. If you only sell your excess, you ought to get at least the utility's incremental operating cost. Operating cost is what it would cost the utility to generate the power itself, using its present generators, that is, incremental fuel cost, including transmission losses, plus the incremental maintenance costs. The incremental fuel cost is the cost of the fuel the utility would use to make the power you actually replace, the fuel that would be used in the utility's most inefficient generators that it turns off first and turns on last. You should argue that incremental, not average, fuel cost is the lower limit of what your electricity is worth to the power company.

If you decide not to sell all your electricity to the utility, what should you pay for standby power? The rate will follow a structure something like the one described above, but you can argue about specific charges. Like any other customer, you pay a combination of operating and capital costs. These can be classified as generating costs (generation plus transmission) and distribution costs.

The generation capital cost is likely to be difficult to negotiate. Your utility argues that your charges should be based on the peak demand rates they would ordinarily apply to a large user. But your outages are statistical, not part of the demand curve. You can argue that if they were serving a number of cogenerators (and utility rates are, after all, designed for classes of users) the probability of their all being out of service and demanding backup simultaneously would be negligible. Therefore the utility should charge you only for your fair share of its generating capacity, based on the amount of electricity you actually buy.

You will also have to pay your share of the cost of the distribution system you use as part of your standby rate. If the distribution charge is customarily embedded in an energy rate, the utility will probably want to calculate a specific charge for you, since you will be buying less electricity than the average customer.

Constraints and Regulations

The Law and the Community

You will be dealing with a maze of legal constraints and regulations on the national, state, and local level. You will have to identify and comply with the laws on air

pollution and other environmental impacts, building codes, health and safety, fuel conversion, and sales of electricity. Other laws may also apply.

This section gives you advice on how to find your way through the confusion. But the particulars vary with the institution, the choice of system, and the locale, so that the advice given here is general.

Remember that very often legal and regulatory problems are actually problems in community acceptance. After all, the laws are for the protection of the citizens. If people feel threatened by your cogeneration plant, they will search out all possible legal challenges. There are many gray areas in these laws, and community opposition will at the very least cause unfavorable publicity, serious delays, and added cost. "Town" and "gown" almost always have some friction. Therefore, a serious approach to the community with early notice and full disclosure of your plans is a vital part of the project.

Getting the community to accept your facility is not just a public relations matter. Remember that the local area is likely to suffer increased air pollution from your extra machinery and disturbance from added fuel deliveries, and that people will have to look at your new smokestack. And they will not get any direct benefits.

On the other hand, energy conservation and a reduction in total air pollution benefit the whole community. People will usually respond favorably to cogeneration if you listen seriously to their concerns and work with them to minimize local impacts. For example you can schedule fuel deliveries the least disruptive way. You can consult the community on the design of the plant and make a reasonable tradeoff between visual blight and pollutant dispersal. And you can cooperate with the community in measuring, modeling, and monitoring your plant's impact on local air.

Air Pollution Regulations

The kinds and amounts of things you put into the atmosphere depend on your fuel and the technology used in the plant. In general, cogeneration decreases regional fuel use. But it is likely to increase local fuel use, since your electricity is ordinarily not generated locally. Therefore you can expect a regional decrease in air pollution, but a local increase. What this means depends very much on your locale. If the region is rural and the local area is urban, for example, cogeneration emissions will be more of a problem than if the whole region is already suffering from air pollution.

If your cogeneration system uses a fuel different from the utility's or different from your present one, you will have to take account of differences in type of emission as well as in quantity. Since you are likely to use steam turbine systems either with your present boilers or with a similar system, you'll be using the same fuel and producing the same sorts of emissions. The percentage increase in emission will likely be quite small. On the other hand, under present air quality legislation, installing steam turbines counts as a major change, and you may find the consequent environmental regulations hard to meet. This is especially true if your installation is large, as is typical of steam turbines, or if your system burns coal, as only steam turbine cogeneration systems do at present.

Gas turbines and diesels usually run on clean fuel and are low in particulate and SO_2 emissions, though a gas turbine or diesel burning residual oil puts out SO_2. Gas turbines emit rather more and diesels a lot more NO_x than ordinary boiler systems.

The Environmental Protection Agency (EPA) administers air quality regulation, but you will deal with your state's department, which has the day-to-day responsibility under its State Implementation Plan (SIP) for emissions control. It is important to talk to the state people even before you have settled the details of your facility, so they can help you spot problems while your plans are still flexible. They will work with you during the planning stage so relevant regulations won't catch you by surprise. They will also tell you what sorts of environmental evaluations or impact statements you will need.

There are two kinds of regulations, those dependent on the facility and those dependent on the locality. The first are New Source Performance Standards (NSPS). They limit the amount of each kind of pollutant any kind or size of new combustion device can put out, independent of where it is and how it is run.

NSPSs to go into effect in June 1982 limit NO_x emissions from internal combustion engines (diesels and gas engines) and gas turbines. They limit SO_2 emissions from gas turbines using oil with more than .8 percent sulfur content. NSPSs already in effect limit NO_x, SO_2, and particulate emissions from boilers whose fuel input is greater than 250×10^6 Btu per hour.

NSPSs for individual devices are in large part the manufacturer's headache. One thing you may have to worry about are the new standards for NO_x just now being introduced. They may drive some diesel engines and gas turbines out of the market if manufacturers can't meet the new standards.

On the other hand, the responsibility for meeting NSPSs for whole systems rests squarely on you. If you assemble a system that may contain equipment bought from several different manufacturers, you or your engineers are responsible for seeing that standards are

actually met. You must see to it that the necessary operating requirements are maintained and you should be alert to the possibility that such requirements may lead to inefficiencies. Boiler standards are more stringent if the boiler is part of an electricity generating system and you sell more than one third of your capacity. So if you install a steam turbine system, the EPA may require monitoring of your actual plant emissions.

The regulations dependent on locality are National Ambient Air Quality Standards. These are listed in Table D. They set emissions limits depending on existing air quality and are very complicated. For each of five pollutants, your locality is an attainment area if it meets standards and a nonattainment area if it doesn't. If it is an attainment area, you can add to the total of the pollutant in question at a rate determined by the locality's subclassification. Class I, national parks and the like, permits almost no additional pollutants. Class II, "clean areas," permits modest additions. Class III permits substantial additions. If your locality is a nonattainment area, life is altogether harder. The limits on how much of the pollutant you can emit are much stricter, and you have to find offsetting reductions in air emissions.

Once you have chosen a cogeneration system that you and your state air quality control agency think will comply with the regulations, you need a permit. This requires a formal, multistage review process for each pollutant. Figure 19 summarizes the complicated procedure in a simplified flow chart.

If your new plant can emit less than 100 tons more per year of each pollutant than your present plant, the permitting process is comparatively quick and simple. Unfortunately, only the smallest plants can achieve such a level. Table E gives maximum plant sizes achieving the level for the critical pollutants, NO_x and SO_2, taking fuel and engine type into consideration. Particulates may be the limiting pollutant for coal-fired systems. The other two regulated pollutants, CO and

TABLE D
National Ambient Air Quality Standards

Pollutant	Averaging Time	Type of Average	Primary Standard (h) Average Concentration $\mu g/m^3$ (d)	Primary Standard (h) Average Concentration ppm (e)	Secondary Standard (i) $\mu g/m^3$	Secondary Standard (i) ppm
Sulfur oxides (SO_2)	Year	Arithmetic Mean	80	0.03		
	Day	Maximum (a)	365	0.14		
	3 hour	Maximum (a)	None	None	1,300	0.5
Total Suspended Particulates (TSP)	Year	Geometric Mean	75	—	60 (b)	—
	Day	Maximum (a)	260	—	150	—
Carbon Monoxide (CO)	8 hours	Maximum (a)	10 (milligrams)	9	same (g)	same
	1 hour	Maximum (a)	40 (milligrams)	35	same	same
Photochemical	1 hour	Maximum (a)	160	0.08	same	same
Hydrocarbons (Non-methane) (f)	3 hours	Maximum between 6 & 9 a.m. (c)	160	0.24	same	same
Nitrogen dioxide (NO_2)	Year	Arithmetic Mean	100	0.05	same	same

(a) National standards other than annual average may be exceeded once a year.
(b) A guide to be used in assessing implementation to achieve the 24-hour standard.
(c) A guide to be used in assessing implementation to achieve a 1-hour photochemical oxidant standard.
(d) Micrograms per cubic meter.
(e) Parts per million.
(f) The EPA sets guidelines only, not standards, for hydrocarbons.
(g) "Same" means same as primary standard.
(h) Primary standards are health-related.
(i) Secondary standards are not health-related.

Table taken from *Cogeneration: Its Benefits to New England*, Final Report of the Governor's Commission on Cogeneration, Massachusetts, October, 1978, p. 140.

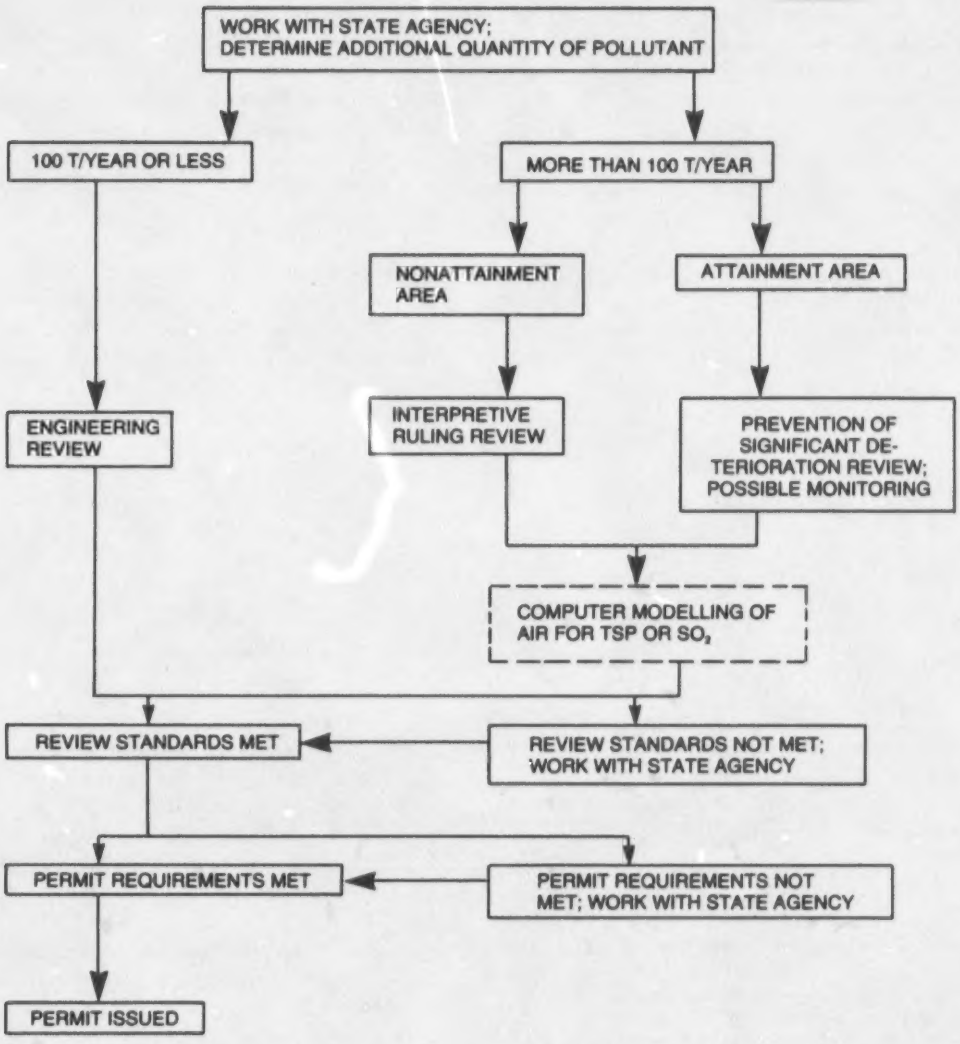
WORK WITH STATE AGENCY; DETERMINE ADDITIONAL QUANTITY OF POLLUTANT
100 T/YEAR OR LESS
MORE THAN 100 T/YEAR
NONATTAINMENT AREA
ATTAINMENT AREA
ENGINEERING REVIEW
INTERPRETIVE RULING REVIEW
PREVENTION OF SIGNIFICANT DE-TERIORATION REVIEW; POSSIBLE MONITORING
COMPUTER MODELLING OF AIR FOR TSP OR SO_2
REVIEW STANDARDS MET
REVIEW STANDARDS NOT MET; WORK WITH STATE AGENCY
PERMIT REQUIREMENTS MET
PERMIT REQUIREMENTS NOT MET; WORK WITH STATE AGENCY
PERMIT ISSUED

FIGURE 19. Generalized Permit Process for Each Pollutant

hydrocarbons, are not likely to be the limiting ones.

The simplified permitting process applies to some additional steam turbine systems and temporarily to some diesels and gas turbines. Steam turbine systems are eligible if their maximum potential emissions are less than 250 tons per year for each criteria pollutant. Such systems must be based either on a single boiler with a maximum fuel input less than 50×10^6 Btu per hour or on a set of boilers with an aggregate maximum fuel input less than 100×10^6 Btu per hour. Diesel and gas turbine systems are eligible for simplified permitting until June 1982 if their maximum potential emissions are less than 250 tons per year for each criteria pollutant. In June 1982, the 100-ton limit goes into effect.

If your new plant can emit more than 100 tons per year more than your present plant of any of the five criteria pollutants, and you don't qualify for one of the exceptions mentioned above, you will come under the regulations for major new sources and major modifications. You will have to go through an air quality review that may include monitoring and modeling requirements. For attainment areas you will have to qualify under Best Available Control Technology (BACT) regulations. For nonattainment areas you will have to find offsets and qualify under Lowest Achievable Emission Rate (LAER) standards.

Your state may have additional regulations for emissions near special areas like wetlands. Ask your state environmental office.

TABLE E
Maximum Size of Cogeneration Plants Emitting 100 Tons or Less Per Year of NO_x or SO_2

Plant type & pollutant	Size plant needed to emit 100 tons pollutant annually, considering plant electrical efficiency
DIESELS	*30% Efficiency*
Nitrogen oxide emissions	
6 gm/hph	1.5 mw
Sulfur dioxide	
0.3% sulfur in oil	6.5 mw
1.0% sulfur in oil	2.0 mw
GAS TURBINES	*25% Efficiency*
Nitrogen oxide emissions	
0.3 lb/million Btu	3.0 mw
Sulfur dioxide	
0.3% sulfur in oil	5.5 mw
1.0% sulfur in oil	1.5 mw
2.0% sulfur in oil	0.8 mw
STEAM TURBINES	*15% Efficiency*
Nitrogen oxide emissions	
0.3 lb/million Btu	3.5 mw
Sulfur dioxide	
0.5% sulfur in oil	2 mw
1.0% sulfur in oil	1 mw
2.0% sulfur in oil	0.5 mw

ASSUMPTIONS
Fuel used is oil. 8760 hours per year = 100% load capacity. 0.142 lbs sulfur dioxide per gallon for each percent sulfur in oil.

ABBREVIATIONS
gm = grams; hph = horsepowerhour; mw = megawatts; lbs = pounds.

NOTES
Nitrogen oxide emissions are a mixture of nitric oxide (NO) and nitrogen dioxide (NO_2).

This table shows that only fairly small cogenerators emit fewer than 100 tons per year of individual pollutants, and can therefore receive approval after a simple engineering review. A small residential college such as Clark University, with approximately 2,000 full-time students, requires about 1.5 mw of capacity to meet its electrical needs, while a medium-to-large shopping center requires about 5 mw. Furthermore, if a site were to cogenerate to satisfy its heating requirements, rather than its electrical needs, a larger facility would probably be required. Cogenerators requiring less than 0.5 mw of capacity do not appear cost-effective at this time.

Two examples of nitrogen oxide emissions for diesels are given to show variation among different plants. The "cleaner" diesel emits only 3 grams of nitrogen oxides per hph, the "dirtier" diesel emits 9 grams nitrogen oxides per hph.

All sulfur emissions depend on percentage of sulfur in fuel.

Table adapted from *Cogeneration: Its Benefits to New England*, Final Report of the Governor's Commission on Cogeneration, Massachusetts, October, 1978, p. 62.

Other Environmental Constraints

Other possible environmental impacts you have to clear through your state environmental agency are solid waste, discharges into the water table, and noise. None of them should cause any particular problems.

The only solid waste you might have is ash from burning coal. You need to use an approved landfill.

Water pollution can be a problem if you are treating fuel oil, washing sodium out of it, for example. You can avoid significant pollution by using skimming tanks. Water losses from steam generating plants could conceivably also be a problem. You might release chromates from cooling towers, for example.

Gas turbines and diesels are noisy. If your system uses these, then noise control is necessary. It costs money, so consult a specialist in sound control. Environmental regulations merely require that people outside of your property not be exposed, but in a college environment your concern is also with people on your property. If you design your system so that it doesn't bother people on campus, you will be well inside regulatory limits.

Building Codes and Health and Safety Regulations

You have to meet conditions for safety of the plant and its operations.

Fire regulations are under the jurisdiction of your local and state fire departments. They include construction requirements for fire doors, fuel tanks, and the like. Your physical plant administrator and building contractor will know how to comply with the fire laws and get approval from the local building authorities.

Occupational safety is under the jurisdiction of the Occupational Safety and Health Administration (OSHA). Your only new problem is likely to be noise in the plant. Gas turbines and diesels can run unattended most of the time, so for them the best solution is to isolate the engine from the control room and to require that people in the engine room wear ear protection. Steam turbines have the same noise and safety problems as your present boiler system. If you install a high pressure boiler you may have to deal with changes in building construction requirements and operating personnel qualifications.

If you plan to modify an old building, check that it is not on the National Register of Historical Buildings. Federal and state regulation limit the use of public funds for such modifications.

Fuel Conversion Regulations

The Powerplant and Industrial Fuel Use Act of 1978, part of the National Energy Act, requires that new units with fuel input capacity of 100 million Btu per

hour and aggregates with 250 million Btu per hour capacity convert to coal use.

This is fine if you want to cogenerate with steam turbines. It could be a problem if you have a large campus but want to cogenerate with gas turbines or diesels. In this case, however, you may be able to get an exemption from the Energy Secretary as a cogeneration facility. As soon as you have some idea of the size of your plant and the percentage of electricity to be sold, ask DOE if the act applies to you and, if so, how to qualify for an exemption.

Constraints on Selling Heat and Electricity

If you set out to sell heat or electricity instead of using it all yourself, you are going to run into problems. There are a number of possible conflicts between your status as a college or university and your status as a power producer.

First, you may find yourself subject to regulation by your state public utility commission. Many states classify anyone who sells power as a utility, and therefore subject both to burdensome requirements for keeping and filing records and to control of operating practices. On the other hand, utility commissions usually have wide discretion in deciding how much to regulate, and many states are even beginning to exempt cogenerators who sell only to a utility. Classification as a utility does not mean that you can sell electricity in competition with your local power company. Restrictions vary from state to state, but most states forbid sales across a right-of-way. So chances are your only customer can be the utility.

In any case, it is important for you to talk early in the planning stages with both your state public utility commission and a lawyer who knows something about utility regulation.

Next, you may need to think about your college or university charter and whether the conditions it sets up for your nonprofit status permit sales of heat or power. Again, talk to a lawyer. Usually the argument can be made that the primary purpose of the cogeneration plant is to provide services to the campus. If heat or electricity sales are incidental, a means of reducing overall energy costs rather than of producing a net profit, they may be adjudged legal under a nonprofit charter.

Finally, you may have to contend with whatever local zoning ordinances cover your institution's land. If they prohibit commercial activity, you will again need to consult a lawyer. Again, it is possible to argue that selling heat or electricity is not a business of the university's but incidental, like selling books in the college bookstore.

Appendix B provides a checklist on legal and regulatory constraints.

Conceptual Design and Case Studies

Goals and Procedures

When you make a conceptual design of your cogeneration system, you want it to accomplish four things: (1) to choose the best system to satisfy the various energy needs of your campus, (2) to provide material for economic and environmental evaluation of your chosen system, (3) to identify unsolved problems and loose ends that you should straighten out, and (4) to provide a basis for the actual detailed design of the plant.

You will probably want to involve one or more consulting firms in the process. Since the results will serve as the basis for the actual design, the people who will be making the final design should be in on the early stages. Selection of consultants and allocation of tasks are described in Chapter 6.

Here are the stages of the conceptual design.

Broad survey. Make a preliminary analysis and economic comparison of a number of sample systems. Include all the types and sizes of systems you think might be reasonable after doing the crude analysis. If you are absolutely certain you are only interested in coal-burning systems, for example, you don't have to analyze gas turbines or diesels, but can limit yourself to a representative set of steam turbines, condensing and noncondensing. If you are only pretty certain you want coal, you could include the most likely diesel to convince yourself. If, on the other hand, your school is small and burns oil, you probably want to look mainly at gas turbines and diesels.

For each system in the survey you should get or make estimates of its physical dimensions, thermal and electrical efficiencies, output based on the efficiencies and your load curves, fuel costs, maintenance costs, revenue from sales, and capital costs. The capital cost estimate should include costs for equipment, a new building or building modifications, heating plant modifications, distribution systems, design costs, and the like.

To compare the systems, choose a simple indicator of the quality of the investment, like the first year return. Calculate the return, or whatever indicator you choose, for each system, basing your figures on cost estimates and either current or predicted fuel and electricity prices. Chapter 4 describes a simple accounting procedure for the calculation of first year operating savings. Then you can compare all the systems in your survey on the basis of the economic indicator you have chosen.

System selection. Identify the ideal system. If possible, narrow down to a single choice, not necessarily a system in your survey. You can ask what makes one of your sample systems better than another for you. You might find, for instance, that for your school diesels outperform steam turbines. Then by looking at a mix of sizes, you should be able to make a good estimate of the best size.

Equipment. Find equipment that matches the ideal system you have defined as closely as possible. For the moment you can limit your search to major components: engine, generator, heat recovery equipment, fuel handling equipment, exhaust system, and major modifications in distribution systems or end use equipment. For each component you need the following information: (1) a price quotation; (2) the physical dimensions and clearances needed for servicing; and (3) operating characteristics, including electrical and thermal efficiencies at full and part load, emissions data, reliability, and operating and maintenance requirements. Make sure all the components match, so they can actually be assembled. From the operating and maintenance requirements you can also determine your manpower needs. If the system requires additional manpower, it may be prohibitively expensive and you should explore your alternatives again.

Layouts, efficiencies, emissions data. Make sample layouts for these major components and connecting piping. These will tell you the space requirements for your system. Calculate detailed mass flows and heat balances for your system under both full- and part-load operation. Using these as a base, calculate thermal and electrical efficiencies for the system. Prepare a table of emissions under full-load operation. Estimate the hourly and yearly emission rate both for the five pollutants for which there are standards and for hydrocarbons under both full-load and normal operation.

Capital cost estimate. Prepare a capital cost estimate for your cogeneration plant based on the information gained in the conceptual design. It should include the quoted prices for all major equipment and cost estimates for a new building or building modification based on space needs, heating plant modification, electric and control systems, engineering and design, and anything else your special situation may require.

Energy use. Using your load curves and the efficiencies calculated above, figure out expected thermal and electrical outputs of your system, fuel requirements, backup heat and electricity needed, and amount of heat or electricity you can sell. Compare fuel use in your present system and your cogeneration system.

The details of the conceptual design depend crucially on the special characteristics of your campus. You and your consultants will have to work them out. The following two case studies illustrate the process. They describe how the conceptual design was done at Clark University and the University of Minnesota under DOE's program for demonstrating a grid-connected Integrated Community Energy System (ICES).

Case Study: Clark University

Clark has 2000 students, including 200 graduate students. Twelve hundred live on campus. The 35-acre campus has 20 major buildings ranging from 1 to 100 years old, with about 800,000 square feet of floor space. The central steam plant, located in the basement of the original college building, Jonas Clark Hall, consists of three boilers. Two are rated at 16,000 lb/hr, one at 25,000 lb/hr. Their capacity substantially exceeds Clark's peak demand of 30,000 lb/hour. They burn No. 6 oil and produce 125 psig steam. The steam distribution system has parts at three different pressures, 125, 40, and 15 psig. Clark's peak electrical demand is 1500 kw. Figures 15 (page 21) and 17 (page 23) show Clark's electrical and thermal load profiles.

Clark considered a dozen sample generating systems, including diesel systems varying in size (700-4500 kw), in cooling temperature (water cooled and ebulliently cooled), in fuel (No. 6 oil, No. 2 oil), and in configuration (two or three small diesels or a single larger one). The samples also included a gas turbine system and two steam turbine systems, one with an extraction noncondensing turbine, the other with an extraction condensing turbine.

Clark also considered the feasibility of converting part of the distribution system from steam to hot water, to utilize jacket heat from a water-cooled diesel. Finally, Clark compared the merits of putting the cogeneration system in the basement of Jonas Clark Hall, next to the existing boiler room, with putting up a new building for it just outside Jonas Clark Hall.

The economic comparison among the systems was based on current fuel, equipment, and labor costs and the terms of interchange negotiated with the New England Electric System. The agreement was that Clark would use the electricity it needed, sell the excess to the utility for the utility's incremental fuel cost, and buy standby electricity at a standard rate with an added distribution charge.

For each sample system, the Clark team calculated the electrical output to be used on site, the electrical output to be sold to the utility, and the thermal output. They used the thermal and electrical demand curves plus some simple information on thermal and electrical demand correlation.

Appendix C provides a checklist on conceptual design.

For illustration, Figures 20 and 21 show outputs of two of the sample systems, a 1500 kw diesel, and a

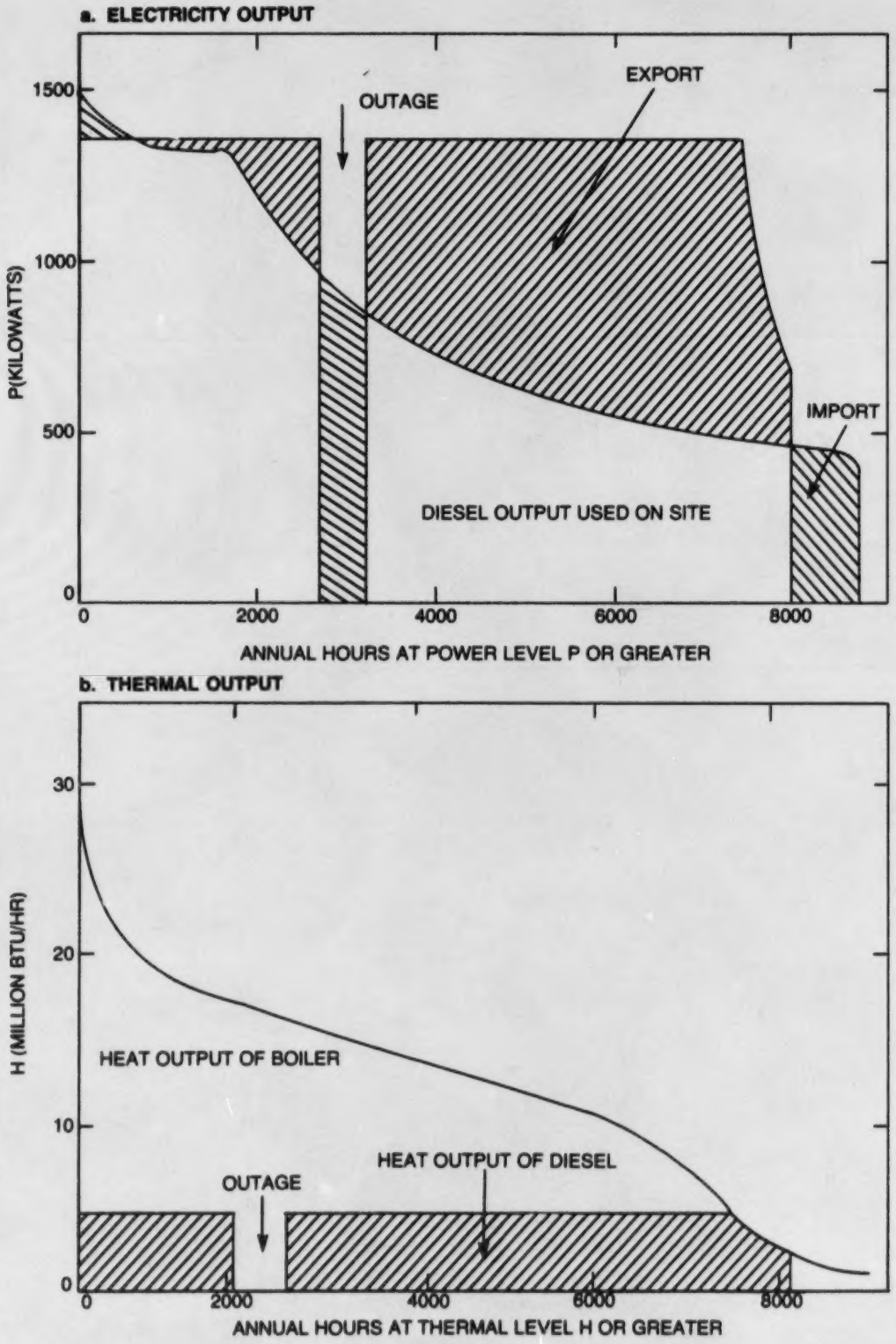

FIGURE 20. Sample System: 1500 kw Diesel, Heat and Electricity Outputs

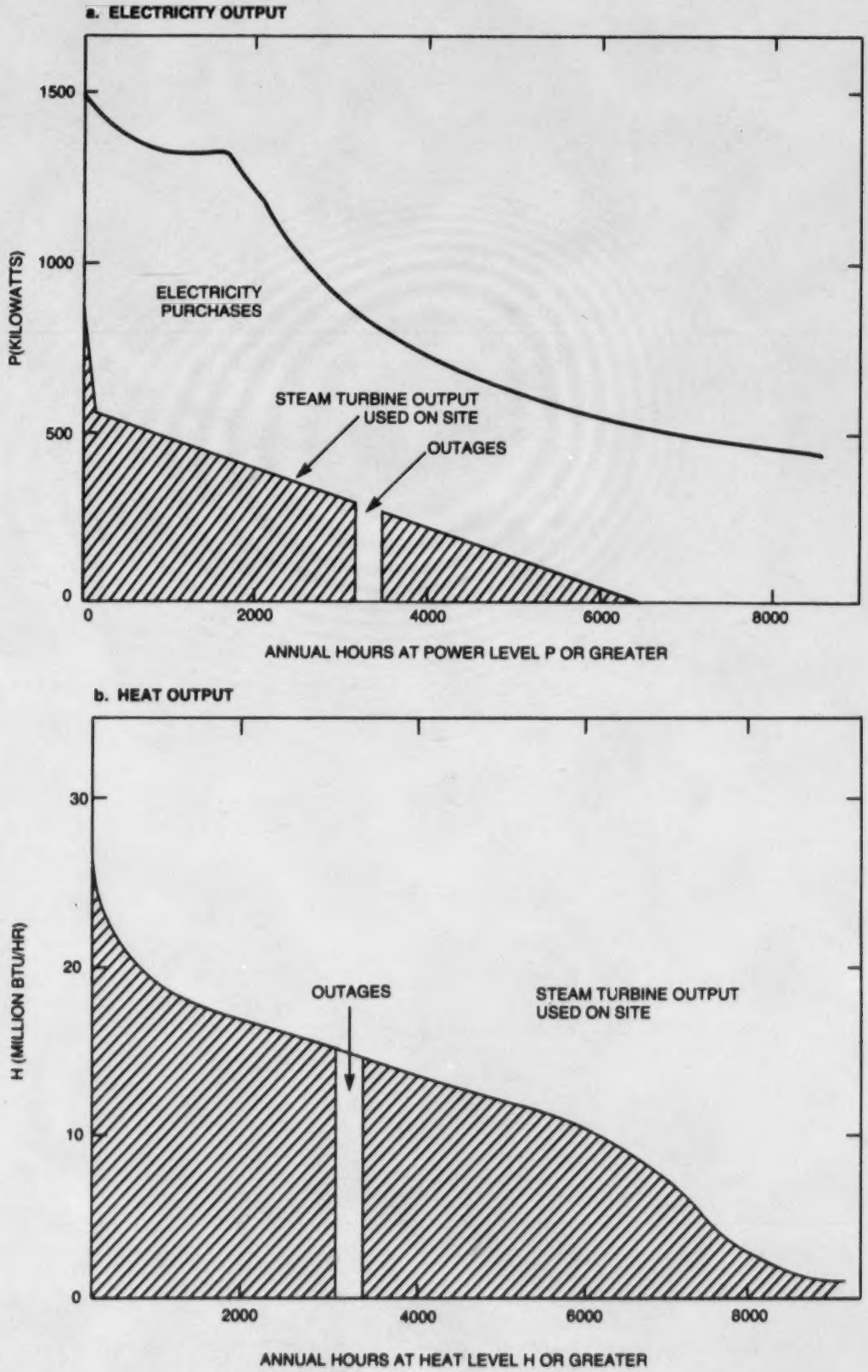

FIGURE 21. Sample System: 900 kw Steam Turbine, Heat and Electricity Outputs

900 kw steam turbine. In each case, only a very little information about the heat-electricity demand correlation was necessary to determine the amount of electricity output used on site. In the case of the diesel, the estimate is simplified because the periods of insufficient thermal demand, summer nights, are perfectly correlated with low electrical demand, while outages and part-load operation are essentially statistical. In the case of the steam turbine the rare periods when electric output is greater than Clark's minimum electric demand also can be treated as statistical since thermal load at Clark does not vary much during a winter day.

The economic comparison gave the following results. The steam turbines were necessarily quite small, so capital costs per unit output were quite high and part-load performance was comparatively poor. Given Clark's heat-load profile, that meant that no size of steam turbine was economical. As a matter of fact, because of poor part-load performance, a steam turbine rated at 360 kw (15 million Btu/hr heat output) would generate more electricity for Clark than one rated at 900 kw (30 million Btu/hr heat output). So steam turbines were ruled out.

Gas turbines were also ruled out. Lower efficiency and higher maintenance costs made them less attractive than ebulliently-cooled diesels.

Diesels were the systems of choice. It did not pay to modify the distribution system, so ebulliently-cooled diesels, producing usable jacket heat, were better than water-cooled ones. The best size was 1000 to 1500 kw, near Clark's maximum demand. Selling excess electricity would have been profitable, but not enough to justify buying extra capacity. No. 6 oil was more economical for Clark than No. 2 oil. Multiple small units seemed attractive for a while, because they could provide electrical backup and load-following, as well as thermal load-following. But Clark's negotiated grid-connection meant that the two first were not needed, and for a 1000 to 1500 kw diesel system thermal load

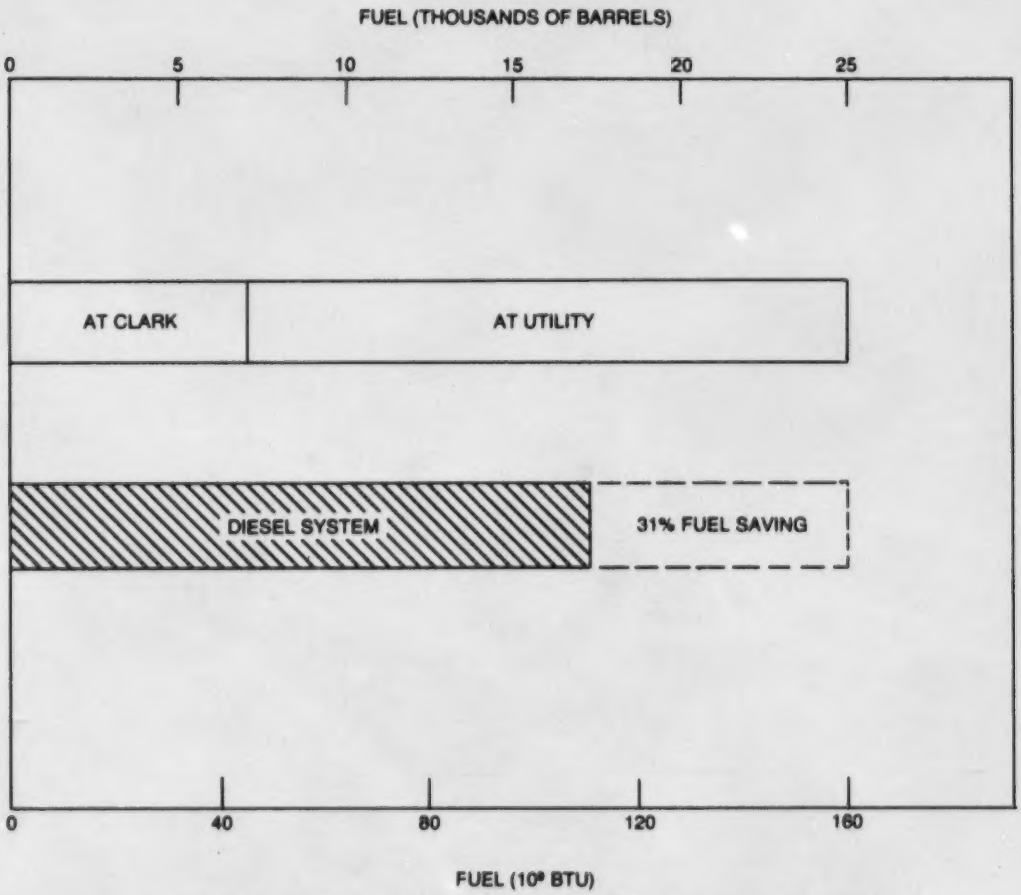

FIGURE 22. Clark University Cogeneration System Estimated Fuel Savings

following is not a problem. So there was no justification for the extra cost and space demands of multiple units.

On the basis of the economic evaluation, then, the best system for Clark turned out to be an ebulliently-cooled 1000 to 1500 kw diesel, burning residual oil. There was no such machine in the original sample, but enough representative systems were in the sample that all the necessary information was there. Estimated fuel savings appear in Figure 22.

The Clark team hunted for such an engine and located two. They also found the other appropriate system components: an ebullient boiler for recovering jacket heat, a waste heat boiler for diesel exhaust, a fuel treatment system to reduce sodium and vanadium levels to the diesel manufacturers' specifications.

The major question left hanging was where the system should go. In favor of putting it in the basement near the existing boiler room were the following: (1) it would be more expensive to build a new building, and (2) putting a new building in the center of a crowded campus is an architectural conundrum. Against the basement were the following: (1) the basement would need significant internal modifications, (2) space was at a premium and there was some question whether everything would fit, and (3) most important, it wasn't clear whether all noise and vibration problems could be solved with the space and architectural constraints.

It was finally decided that the new building was necessary. Figures 23 and 24 give a block diagram of the chosen system and a sample layout.[12]

Case Study: University of Minnesota

The main campus of the University of Minnesota serves 45,000 students. It has more than 200 buildings with about 11 million square feet of floor space on 230 acres which straddle the Mississippi River. The present heating plant consists of six coal-fired boilers ranging from 75,000 to 125,000 lb/hr, and one oil-fired boiler at 200,000 lb/hr. The system uses 150 psig steam.

In 1975 the university started to think about future needs and current capacity. Were they too dependent on oil? Was their capacity adequate for planned cam-

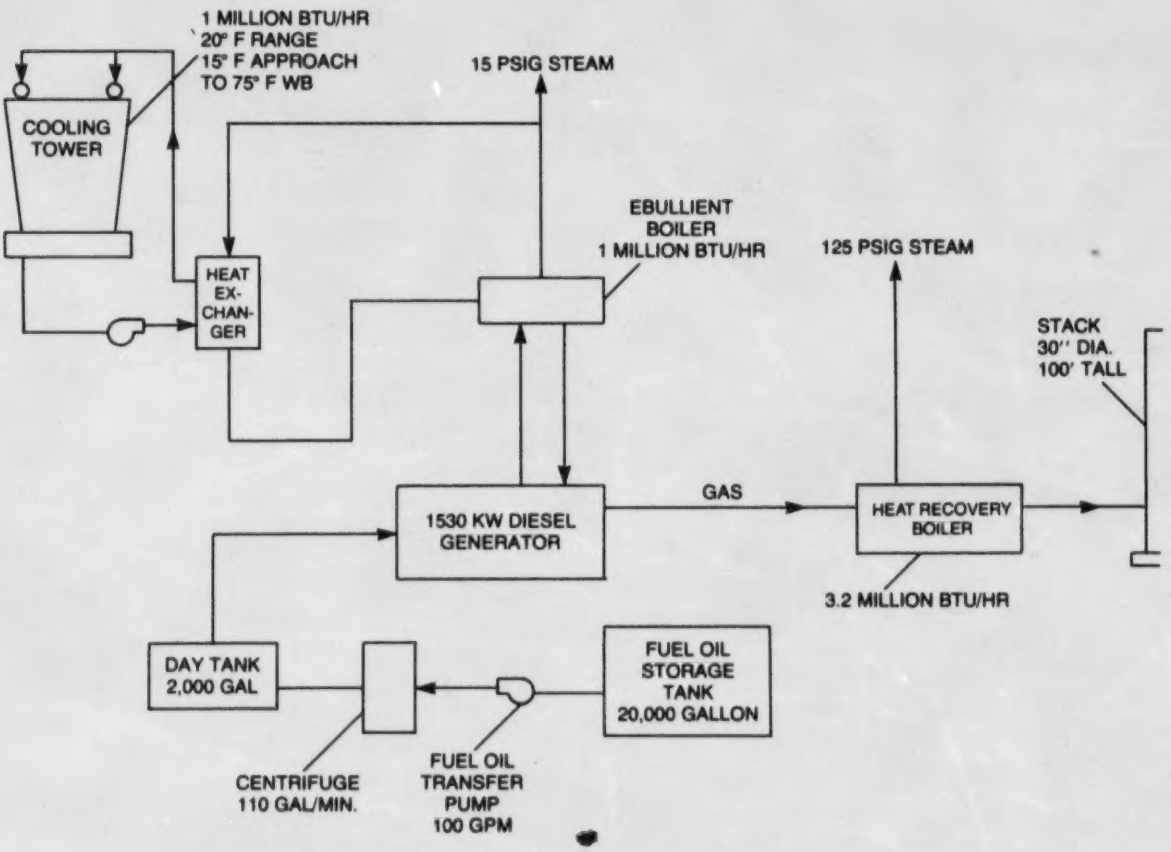

FIGURE 23. Clark University System Block Diagram

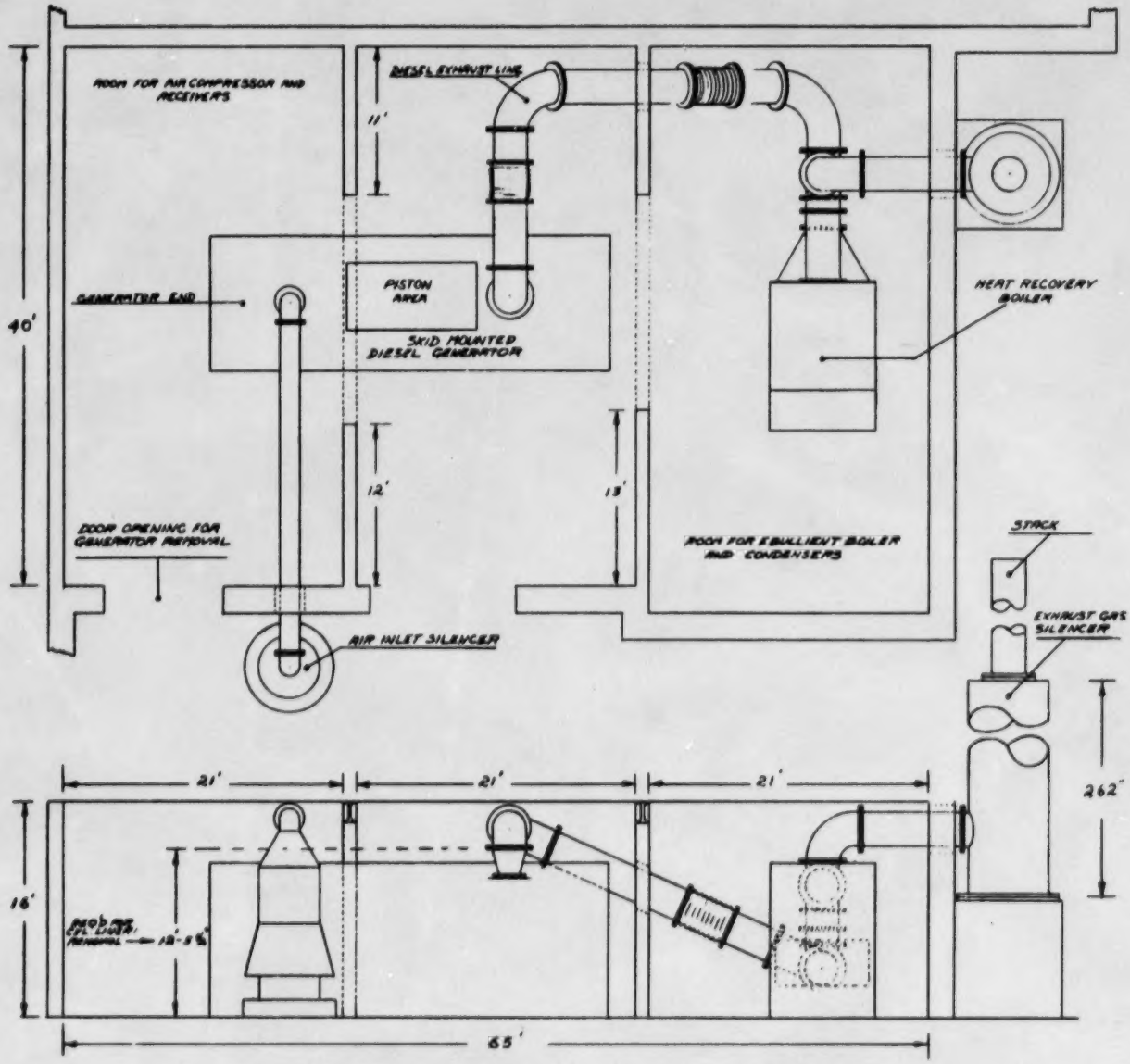

FIGURE 24. Clark University Sample Cogeneration Plant Layout

pus expansion? They had the chance to buy inexpensively an old utility steam plant adjacent to the campus, half a mile upriver from the central heating plant.

Originally they planned to rehabilitate the steam plant, convert one boiler to coal, run a tunnel to carry the steam to the central plant, and use the new plant only in winter to meet peak thermal demands. Since a major modification was in the works, it seemed sensible to go further and plan for cogeneration.

Since Minnesota had decided that coal was the fuel of choice, they only considered steam turbines. Their survey included systems with a single straight noncondensing steam turbine in 5, 7½, and 10 mw (megawatt) sizes, a pair of 7½ mw straight noncondensing steam turbines, a 7½ mw extraction condensing steam turbine, and a 7½ mw extraction noncondensing steam turbine. Since they had made arrangements to sell all of their electricity output to Northern States Power, for each of these cases they could predict the total electrical output simply by using their thermal load curve, Figure 18 (page 24), and the properties of the system at each load level.

The university team also thought about changing from steam to hot water distribution. They thought about installing a waste burning unit. They considered adding two adjacent hospitals and a college as steam customers. They debated two arrangements for their electricity, using it all on site or selling it directly to the utility, at a price comparable to what the utility pays other power companies. Finally, they contemplated their coal handling capacity and compared updating their barge facilities with updating their rail facilities.

The generating system chosen was a 7½ mw automatic extraction noncondensing turbine. A straight noncondensing turbine of the same size gave a similar return on investment, but the extraction turbine offered more flexibility. It would produce more electricity if the university decided to convert later to a hot water distribution system. Immediate conversion turned out to be uneconomical, as was the waste-burning plant.

The university made satisfactory agreements to sell its electricity directly to Northern States Power Company, and to supply steam for St. Mary's and Fairview Hospitals and Augsburg College. They decided to improve their rail facilities and coal handling, since improving the barge facilities turned out to be prohibitively expensive. And they arranged to share unit trains with Northern States Power to reduce the price of coal.

Fuel savings are shown in Figure 25. The proposed plant layout is shown in Figure 26.[13]

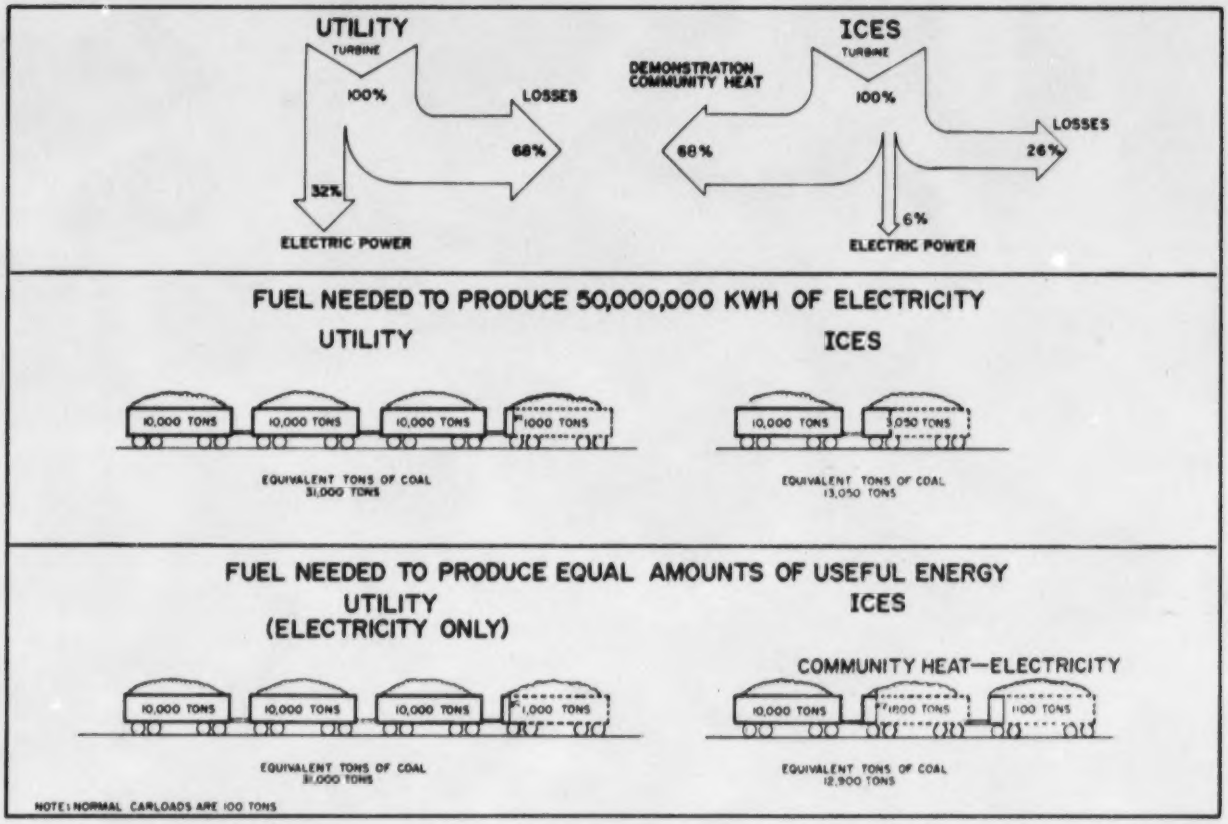

Figure taken from *Grid-Connected Integrated Community Energy System, Executive Summary.* Final Report. Phase I, February 1, 1977-May 31, 1977. University of Minnesota, June 1977.

FIGURE 25. University of Minnesota Cogeneration Fuel Savings

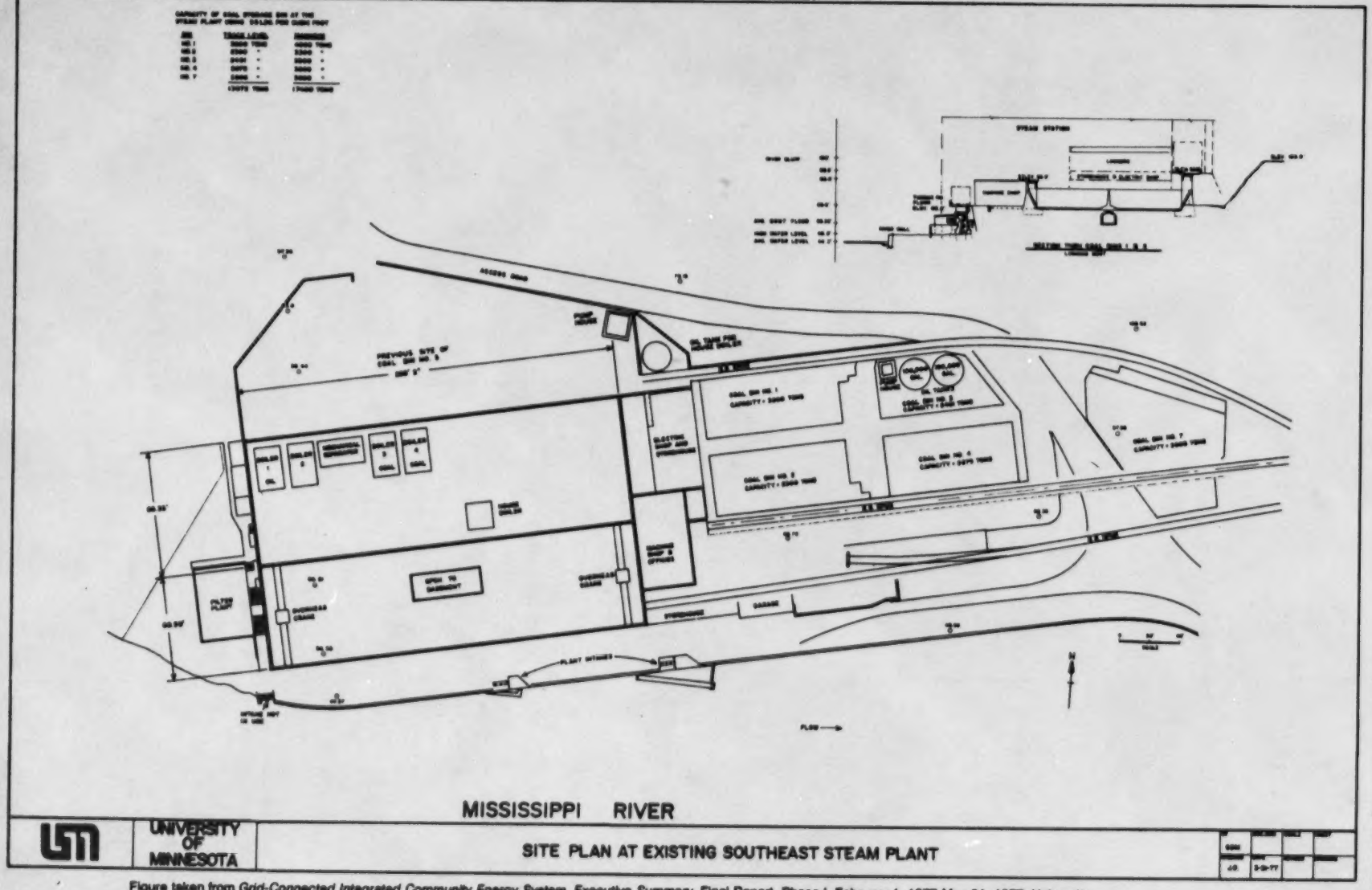

Figure taken from *Grid-Connected Integrated Community Energy System, Executive Summary.* Final Report. Phase I, February 1, 1977-May 31, 1977. University of Minnesota, June 1977.

FIGURE 26. University of Minnesota Proposed Cogeneration System Plant Layout

CHAPTER 4

Economic Considerations

Economic Evaluation

General Considerations

In the last analysis, the cogeneration decision has to be made on economic grounds. It is good to save energy. It is important to keep the environment clean. But you will have to convince whoever runs your institution that your cogeneration plant is a sound financial investment.

Whatever your accounting system and economic criteria, the basic idea is simple. The plant has a capital cost. Over its lifetime, it will save in operating costs. The question is, then, do the savings justify the cost.

But the calculation can be complicated by how you finance your investment. The kind of financing you get can really affect the overall decision. If you buy the plant with endowment money or a legislative appropriation, then your investment can be directly compared with other possible investments. But if some or all of your plant is financed by money not available for other investments, a 3 percent federal energy conservation loan, for instance, or a special state bond issue, then you can't simply compare one investment with another, and your evaluation will have to take that into account.

This chapter deals with the general problem of evaluating the plant as an investment as well as finding funds and other financial considerations.

Capital Costs

Your consultants have made a capital cost estimate as part of the conceptual design. How good is it? To evaluate it you can break it down into familiar and unfamiliar costs.

Familiar costs are for a new building or building modification, heating plant and distribution system modification, and the like. You already have experience evaluating estimates for items like these. In addition, you may already have experience with the people making the estimates, so you can judge pretty well on the accuracy of their past estimates. You can make allowances if you know your building contractor is conservative and your plumber optimistic.

Unfamiliar costs, dealing with generating and heat recovery systems and attachments, are harder for you to evaluate. You probably don't know how to estimate the costs of noise reduction for a diesel engine or of controls and other minor system components. For these you have to depend on the experience and good sense of your consultants.

You can't ever be perfectly certain an estimate is right, but you can be fairly certain that it isn't drastically wrong. One purpose of doing a thorough conceptual design is to reduce uncertainty by seeing to it that the costs of the major components are quite well specified.

The condition of your present plant affects your capital cost estimate. It is better to install a new facility when the old one is ready to go. To allow for that financial advantage, estimate the avoided cost of replacement of major components of your present plant over the expected life of the cogeneration plant (20 years for a diesel or gas turbine, 30 or more for a steam turbine); subtract that figure from the capital cost of your cogeneration system.

Energy Costs and Revenues

Figure 27 gives the history of average U.S. prices for electricity and various fuels. There is, of course, substantial local price variation which is not shown. The figure suggests three things: (1) It is rash to try to predict fuel prices. (2) Fuel prices tend to be correlated, to rise and fall at the same time and by similar amounts. (3) The price of electricity also tends to track with fuel prices. The reasons for these correlations have been debated, but most people think they will continue.

What this means is that you can't project confidently too far into the future. Start with current prices. With these and relatively short projections of just a few years, you can calculate fuel costs for your first year or

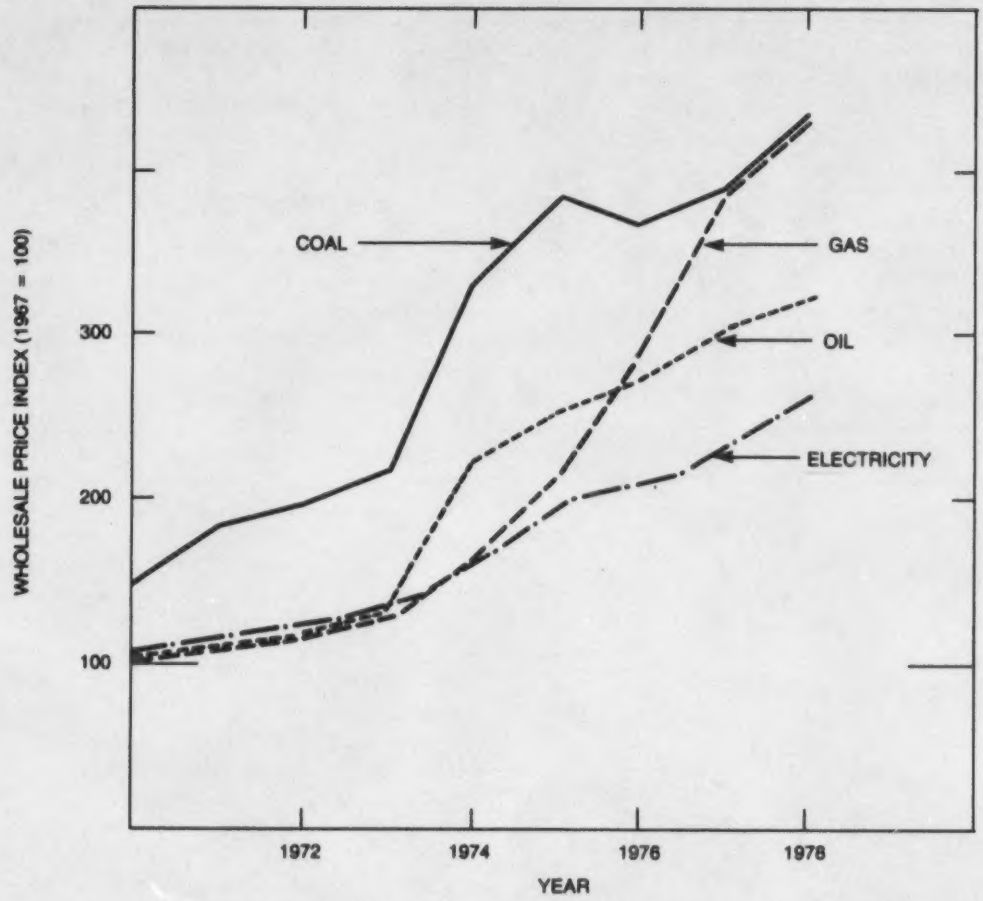

FIGURE 27. Electricity and Fuel Prices

so of operation. For later costs the best you can do is make a guess and estimate the effect of deviations from that guess. The base case and sensitivity analysis calculations described below give a convenient way to do this.

Given fuel prices, how do you figure out how much it will cost you for fuel to generate electricity and heat with your new plant? You need to know the electrical and thermal efficiencies of your system as given in the specs. The electrical efficiency usually appears as a heat rate, the number of Btu of fuel needed to produce one kwh of electricity. The thermal efficiency is the ratio of useful heat output to fuel input. The heat-electricity output ratio is the ratio of thermal efficiency to electricial efficiency, stated as the number of Btu of useful heat produced per kwh of electricity produced.

Figuring out the fuel cost for a diesel engine or gas turbine is easy, since thermal and electrical efficiencies for diesels and gas turbines don't depend very much on engine load—as long as the engine is running at all. (Below a 50 percent load, diesels and gas turbines don't run well.)

To illustrate the calculation, suppose you have a diesel engine with a heat rate of 10,000 Btu/kwh and a heat-electricity output ratio of 4000 Btu/kwh.

From your load curves you will calculate how much electricity you will produce per year. The calculation depends on how you plan to operate your plant. Your criterion might be that you will operate your diesel to the extent that you have need for its thermal output. Then the total electricity output depends only on your thermal load curve and the reliability of your generator. This assumes that you have made appropriate arrangements with the utility. If you do not plan to sell electricity you might have a different criterion such as requiring that you always need both the electricity and the thermal output. In that case you need both your thermal and electricity load curves as well as information on the correlation between them. Once you have determined how much electricity you will

produce, then the fuel cost can be found simply by multiplying the heat rate times the fuel cost in $ per 10^6 Btu times the number of kwh. So in this example, if diesel fuel costs $5/10^6$ Btu, the fuel cost for 1 kwh of electricity plus 4000 Btu of heat is $.05. If you produced 6×10^6 kwh of electricity a year, the fuel cost would be $300,000.

Noncondensing steam turbines are more complicated. Both the heat rate and the heat-electricity ratio depend on load. If the turbine is operated to meet thermal demand, you divide the number of hours at each heat level by the heat-electricity output ratio to find the electricity produced at that heat level and multiply the result by the heat rate to find the fuel used at that level. To find the total electricity produced and fuel used, add the results for all heat levels.

Here is a simple example. Note that the assumptions used here are quite different from the diesel example given above, since steam turbine systems differ from diesels in their heat-to-electricity ratios and the fuel they can burn, as well as in their part load operating characteristics. Suppose you have a boiler that produces steam for a 2 mw steam turbine. Suppose at full load the boiler and steam-turbine system has a heat rate of 31,000 Btu/kwh and produces 25,000 Btu/kwh of heat. Then, at full load it produces 50×10^6 Btu/hr of heat. Suppose at a part load of 700 kw it has a heat rate of 43,000 Btu/kwh and produces 36,000 Btu/kwh of heat. Then it produces 25×10^6 Btu/hr of heat. Suppose that the load curve had a demand of 50×10^6 Btu/hr for 4000 hours, and a demand of 25×10^6 Btu/hr for 4000 hours, and that the price of fuel was $2.50 per 10^6 Btu. Then the fuel cost would be (4000 hr × 2000 kw × 31,000 Btu/kwh × $2.50 ÷ 10^6 Btu) + (4000 hr × 700 kw × 43,000 Btu/hr × $2.50 ÷ 10^6 Btu) = $620,000 + $301,000 = $921,000.

Extraction and condensing steam turbines are too complicated to deal with here. You have a choice in the mix of thermal and electrical output. That means the calculation of fuel use depends not only on turbine efficiencies, but on the way you choose to operate.

You need to allow for outages. Make as good an estimate as you can of expected down-time for the plant and subtract an appropriate amount of fuel from the total you calculate.

You need to add the cost of fuel for thermal backup. From your thermal load curve and your anticipated thermal output, calculate how much additional heat you need. You will presumably use your present boiler. You know its efficiency. So you can calculate how much additional fuel you need and, given a fuel price, the cost of the additional fuel.

Your estimated fuel cost, then, is the cost of cogeneration and backup fuel minus an allowance for outages. To calculate your net energy cost, you have to add the cost of standby electricity and subtract energy revenues.

Standby costs depend on the terms you negotiate with your utility and the amount of electricity you buy. You need to buy power during outages of your plant, which you can estimate from manufacturers' information. You also need to buy power any time your own plant doesn't meet your electric demand. You can calculate how much from your thermal load curve, electrical load curve, correlation of electric and thermal demand, and anticipated plant output. Once you know how much power you need, you can figure out the cost based on your agreement with the power company.

To calculate sales of electricity and/or heat, figure out how much electricity or heat you expect to sell given your equipment and your load curves. Multiply the amount by the projected price. The results are your energy revenues.

Other Operating Costs

These include plant operation, routine maintenance and repair, major overhauls, and fuel treatment if necessary.

Plant operation costs are influenced by manpower requirements. Even for a big plant, just one more operator on each shift would probably add from $50,000 to $100,000 per year. Therefore your conceptual design should keep staff at the present level, so operating costs can stay the same. You need staff changes only if your cogeneration plant includes a steam turbine and uses much higher-pressure boilers than your present system. Then you may have to worry about different licensing requirements for your engineers.

Routine maintenance and repair costs include the price of parts and outside labor as needed for routine inspections, preventative maintenance, and repairs. Ask the manufacturers of your major system components for estimates. These should be based on experience in similar installations. It can also be helpful to contact people at such installations directly.

You can stabilize maintenance costs by negotiating service contracts with the manufacturers' service organizations. But if your personnel do at least the routine work, you will probably save money. They can probably handle diesel maintenance, but it would be a very good idea to have the engine manufacturer train them. Steam turbines give little trouble, so maintenance is mostly in the boiler steam systems, which your staff is familiar with. Gas turbine maintenance, however, takes a specially trained mechanic.

Major overhauls need to be done only every several years. But you should include them in your annual budget. Start accumulating money now for the overhaul you'll need five years from now.

If your system requires fuel treatment, include the cost of chemicals and the fuel treatment system in your account.

Base Case Calculation

To make a financial evaluation of your cogeneration plant you need a base case calculation, that is, an estimate of your operating savings over the life of the plant. Operating savings are the total operating cost difference for a given year between your present plant and your cogeneration plant.

You can use your estimates to predict all costs for the first year of operation of the cogeneration plant and feed reasonably confident. Table F shows this prediction for Clark University. But to make your financial evaluation, you need such information over the entire life of the plant. And that means predicting the future in a big way. As Figure 27 showed, you make such predictions at your peril. So what can you do?

A plausible thing you can do is make some reasonable assumptions about future energy prices. These will give you a base case, your estimate of operating savings. Then you can evaluate the investment by whatever criterion you choose: internal rate of return, cash flows, present value of the investment, or the like. But you don't have to believe in the base case assumptions; you are only using them as a convenient guide. The next section deals with the uncertainties in your base case estimate.

You can take account of financing terms by adding debt repayment and interest to operating expenses. Then net savings are operating savings less capital payments. For example, suppose the Clark University plant illustrated in Table F has a capital cost of $2 million and is financed 60 percent through a 3 percent Housing and Urban Development (HUD) loan and 40 percent through a 13 percent bank loan. Suppose that each is a fixed-payment 20-year note. Then the annual payments will be $80,000 to HUD, and $110,000 to the bank. Then first year net savings are first year operating savings ($200,000) less capital payments ($190,000), or $10,000.

If you assume for the base case that all costs rise at an 8 percent general inflation rate, operating savings increase. Since capital payments remain fixed, net savings increase too. Results for ten years are given in Figure 28.

TABLE F
Clark University
First Year Cogeneration Cost Prediction

Conventional Costs		
Electricity (7×10^6 kwh @ 4.5¢/kwh)	$315,000	
Heating fuel (No. 6 oil) (150×10^9 Btu @ $3.00/$10^6$ Btu)	$450,000	
TOTAL		$765,000
Cogeneration Costs		
Cogeneration fuel (No. 6 oil) (105×10^9 Btu @ $3.00/$10^6$ Btu)	315,000	
Backup heating fuel (No. 6 oil) (90×10^9 Btu @ $3.00/$10^6$ Btu)	255,000	
Additional operation and maintenance	60,000	
Backup electricity	65,000	
Subtotal		695,000
Revenues from electricity sales (4×10^6 kwh @ 3¢/kwh)	−120,000	
TOTAL, Costs less revenues		575,000
OPERATING SAVINGS: $765,000 − $575,000 = $190,000		

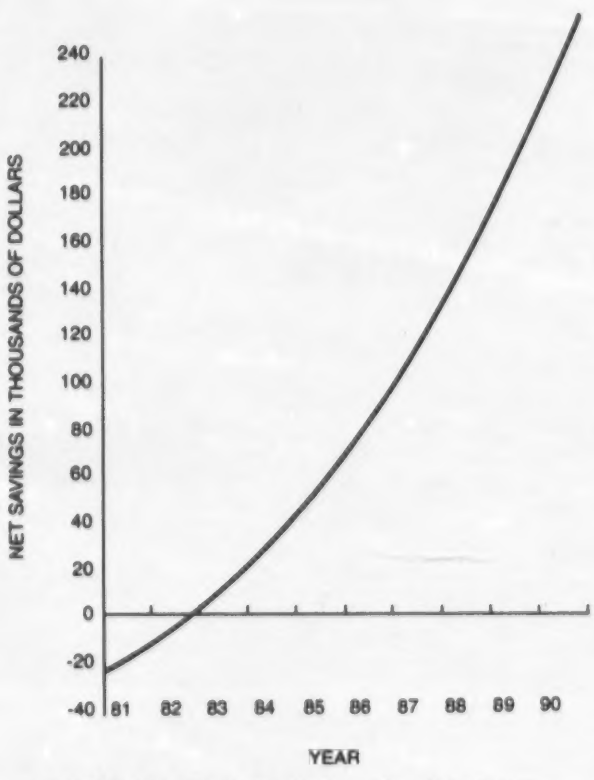

FIGURE 28. Clark University Base Case Net Savings

But do such savings justify the investment risk, given the uncertainties of the prediction? That is a judgment that has to be made by your institution's financial officers. The sensitivity analysis in the next section can help by showing how the uncertainties affect base case savings and how you can give a reasonable answer to the question. But it is an aid to judgment, not a substitute.

Sensitivity Analysis

You are likely to be worrying about a number of the variables that affect your investment, like fuel cost and inflation rate. For a sensitivity analysis, choose a plausible range of variation around your base case for each such parameter. You might choose an inflation range from 5 percent to 15 percent for example. You don't have to include all possible variations. Inflation could shoot up to 30 percent. You are not trying to cover all contingencies; you are trying to find out how important each parameter is. So take a plausible range. Then calculate the effect of the variation of each parameter on your investment criterion (cash flow, payback time, internal rate of return, present value, or whatever). You can also calculate worst case and best case totals that include the effect of varying all parameters simultaneously. For the Clark University cogeneration plant described earlier, Table G gives a list of parameters and the ranges selected. Figure 29 shows the resulting variations in net savings.

TABLE G
Variables for Clark's Sensitivity Analysis

Variable	Base Case	Variation
Effective interest rate	8%	5-12%
Capital cost	$2,000,000	$1,800,000-2,200,000
Capacity factor (actual output/full output)	85%	75-90%
Fuel price escalation rate	8%/year	4-12%/year
Electricity price escalation rate	8%/year	6-10%/year

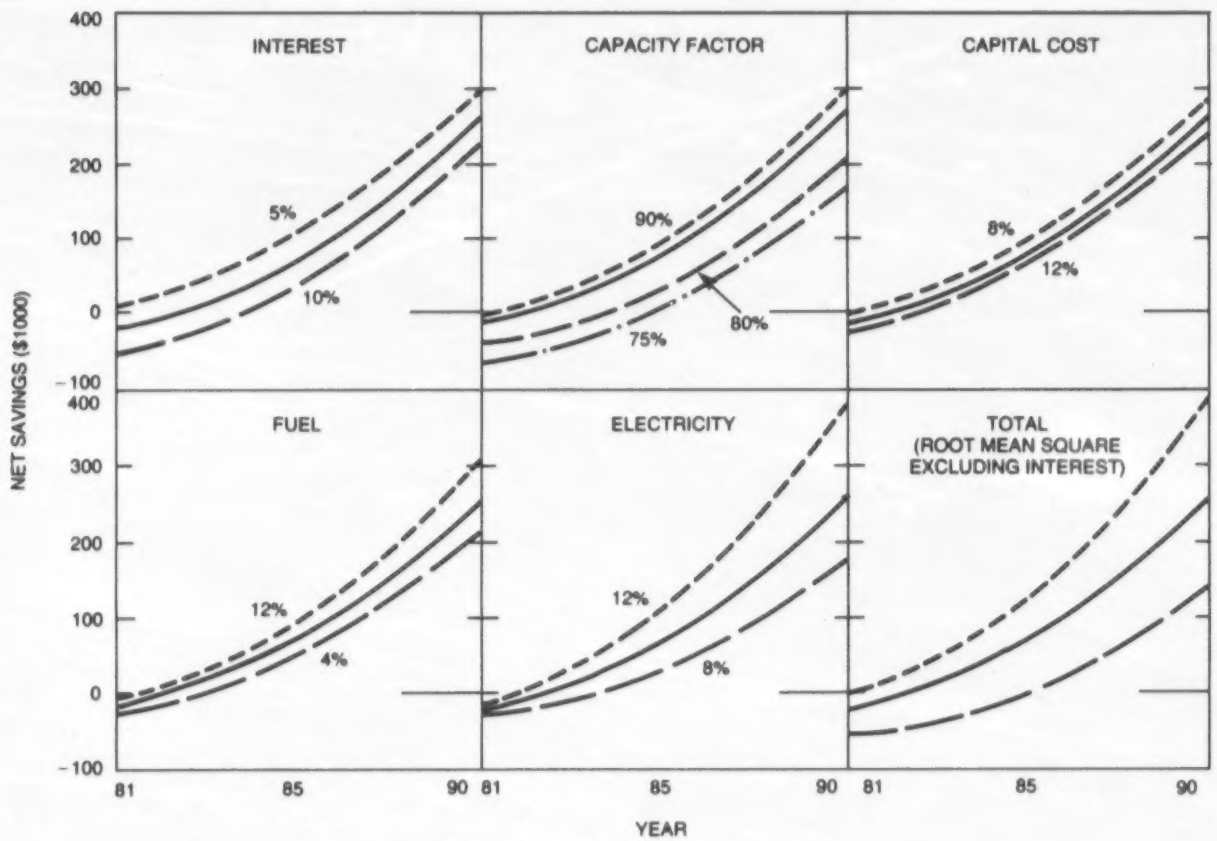

FIGURE 29. Clark University Sensitivity Analysis

Net savings in the example are comparatively insensitive to fuel price variation, though, as expected, higher prices favor cogeneration. This insensitivity is typical of cogeneration investments, because the difference between fuel prices for conventional and cogeneration systems is a relatively small term in the operating savings. This illustrates again that cogeneration is a hedge against inflating fuel prices.

Funding and Financial Considerations

As this manual is being written, interest rates are at their highest levels ever, and the federal government is moving to tighten money. So in one way it is a bad time for trying to finance a new cogeneration system. But in another way it is a good time. Interest rates are high because of a soaring inflation rate. And increasing inflation can make capital investments attractive because they fix costs.

There are five basic financing arrangements. Which ones you can use may depend on whether you are a public or private institution.

Finance it yourself. You can finance your plant out of endowment funds, building funds, or the like. A public school may not have such discretionary funds available. Whether a private school actually does depends on how encumbered its endowment already is. In addition the investment has to meet the criteria the school has established for use of such money.

Borrow money. There are a number of possibilities. Public institutions may not be allowed to take advantage of some of them. Government loan programs for energy conservation on campuses come and go. HUD has a program providing 3 percent loans with 40-year payback for energy conservation in dorms and dining facilities, an outgrowth of earlier dorm construction programs. You can use these loans to finance only that proportion of your system that services dining areas and dorms. HEW (Department of Health, Education, and Welfare) had a similar program on the books. This one covers all campus facilities. Unfortunately, no money has been appropriated for it in the last two years.

Another way of borrowing money is by issuing bonds. Tax exempt bonds now cost about 9 percent per year. Other bond issues are much more expensive. Some state institutions have the authority to issue bonds themselves. Massachusetts has a state agency authorized to issue tax-exempt bonds for private colleges and universities. Check with your state for similar programs.

You can borrow money from a bank. Bank loans can be very expensive, 15 percent per year or more. This may well be prohibitive. (But it is not much more than the current inflation rate.)

Get an appropriation. If your institution is public, you may be able to persuade your state legislature to appropriate money for your plant. You have to convince them that it is worth spending an initial large sum to save on future operating costs.

Get a lease. You may be able to arrange for someone else to buy the plant and lease it to you. One common arrangement is a leveraged lease. An investor buys the plant and leases it to you with suitable arrangements for you to operate and maintain it. He gets tax privileges such as the investment tax credit, accelerated depreciation, and maybe the energy conservation tax credit. The Internal Revenue Service has not yet ruled whether that last credit applies to cogeneration facilities. After some fixed time, the investor sells the plant back to the university. A leveraged lease is likely to have an effective interest rate of about 9 percent.

There are two long shots. Energy investment firms exist which might build and operate the plant and recapture their investment by selling you heat and electricity. Your power company might do the same.

Get a grant. You may be able to get money outright to cover part or all of the cost. Under the National Energy Act DOE has funds for energy conservation in nonprofit facilities. Some part of this money is earmarked for the energy audit program, but there are also funds to match capital investments. Like the audit program, this one is administered through the states. Provisions vary from state to state, so check with your state energy office.

You can always go out and ask for donations. A power plant is not as glamorous as a gym or lab, but cogeneration is an interesting idea. Maybe you can attract the attention of an alumnus with it. Don't neglect the possibility of a donation in kind if you have a turbine manufacturer, say, on your list of donors.

Most likely you will use some combination of these methods. Clark University plans to finance its plant in the following way: HUD loan (55 percent), private donation already received (15 percent), Department of Energy demonstration program money (10 percent), bank loans and/or other grants or donations (20 percent).

CHAPTER 5

The Decision

Steps to the Cogeneration Decision

This manual is a guide, not a prescription. It can help you make up your mind, but it can't make it up for you. The procedures it recommends are necessarily sketchy and general. But if you follow them, learning as you go, when the time comes to make the final decision, you should be ready for it.

You don't have to commit yourself to the final decision all at once. The manual takes you through a series of increasing commitments, so that the decision evolves, rather than coming in one indigestible lump. For convenience, the process is divided into three stages, summarized below.

Step 1. Do you proceed with the conceptual design? At this point you commit yourself to hiring consultants and spending some money. You are looking for a system that will match your present and future energy needs and be acceptable to the trustees, the power company, the community, and the government. There is no guarantee that such a system exists, of course. But you improve your chances of finding it if, before committing your institution to the conceptual design, you do the following:

1. Make a rough evaluation of how promising cogeneration looks for your campus.
2. Make a detailed description of your plant and begin collecting the data you need for detailed electrical and thermal load curves.
3. Identify key people on campus who will participate in your program and assign their jobs.
4. Find consultants to supplement on-campus personnel.
5. Make a budget for the conceptual design and find funding for it.

Step 2. Do you go on to the detailed design? This step is necessary before you build the plant, but if you have done a careful conceptual design, it won't have any stunning surprises for you. You will be working with the people you located for the conceptual design. The detailed design costs still more money, so you should be pretty sure that you know what you are getting into and that you want to build. Again, you are less likely to have to back out with a red face if, before you start the detailed design, you do the following:

1. Complete the conceptual design, including choice of cogenerating system; specification of major components and their operating characteristics; drafting of sample layouts identifying system space and demands; identification of fuel, manpower, and maintenance requirements; and detailed estimate of cost.
2. Make a firm agreement with the electric utility on sales and standby power.
3. Lay the groundwork for getting the environmental permits you need, especially for air pollution, and be fairly certain you can get them.
4. Start to build bridges with the community, both on- and off-campus. Figure out what worries people about a cogeneration plant and how you can deal fairly with their concerns.
5. Get a comprehensive legal evaluation, dealing particularly with problems of selling electricity.
6. Make a financial evaluation of the system and decide if it is a good investment.
7. Make a budget and schedule both for the detailed design and for plant construction. Assign management responsibilities and start collecting personnel.
8. Find an adequate source of funding for detailed design and construction of your cogeneration plant.

Step 3. Should you cogenerate? It would be embarrassing, though not absolutely disastrous, to change your mind once you got started on the detailed design. At some point, however, perhaps before the detailed design is finished, you will want to start ordering equipment. Once you have undertaken such a major financial commitment, you can say you have made the decision.

When Is Cogeneration the Wrong Decision?

You should not even bother to do a conceptual design if any of the following are true:

1. Your institution does not have a basic conservation program. You are not ready to take on hard conservation measures if you haven't yet done the easy ones. Also, you are unlikely to have gathered the information you need to go on.
2. Your rough analysis rates your school as unlikely to benefit much from cogeneration.
3. Your finances are so tight that you feel it would be a waste if the conceptual design doesn't give positive results. Financial pressures of this sort make it tempting to slant the conceptual design. If you proceed on a biased decision, you can get into real financial hot water. Also, if you can't afford the conceptual design, you probably can't afford the plant.

You should stop at the conceptual design if it shows any of the following:

1. You can't get an adequate return on your investment.
2. The risk is too high.
3. You don't see how you can raise the capital to invest.
4. Environmental problems don't seem soluble.
5. You think the local community might sue. Cogeneration can be a good investment, but is unlikely to be good enough to be worth a determined lawsuit.

CHAPTER 6

The Plan of Action

Getting Started

A cogeneration plant is a major investment, and a complicated one. As noted in the last chapter, the decision has to proceed in stages. Top-level administrators should be involved all along so the necessary evaluations and financial decisions can be made promptly. Senior administrators and, if possible, trustees and regents should be involved in approaching and negotiating with the utility and the community. They are even more essential to the search for financing, and to publicity. Remember that if you decide to cogenerate, you can publicize the program—and your institution.

How do you get your senior people interested? Suppose you have gone through this manual, done the preliminary analysis and decided that your campus has a moderate to high likelihood of being suitable for cogeneration. What's the next step? One thing you might do is get a couple of copies of this book for your senior colleagues. It might save you hours of explaining the basic ideas.

If your administrators are at all interested, hold a meeting. Include representatives of the physical plant and the business office. Ask any faculty members who might be useful: an engineer who knows about power plants, someone familiar with environmental regulations, an economist studying utilities. In the meeting discuss first what the basic idea of cogeneration is and then how to institute campus needs analysis and conceptual design. Start planning right away. You have to decide what jobs can be done by your own people, allocate them, and get started on energy data measurements first off. As soon as possible you want to find consultants and approach the electric utility and environmental quality people.

A good beginning is to set up a task force of interested administrators and faculty. They will need a small budget for measuring energy use and for finding consultants. Their job is to plan for the conceptual design. They should figure out who does what, including management and coordination; what can be done by university personnel; and what needs to be done by consultants. They should find the consultants. They should make schedules and a budget. They should see that this miscellany of tasks is coordinated and gets done, so that they can tell people how much it will cost to get through the conceptual design, and they should see if they can raise the money.

By all means, find about about the experience of other campuses, especially ones similar to yours. Appendix D lists cogenerating campuses, their basic statistics, and contact people.

Using University Talent

Here are some of the necessary jobs that might be done in-house.

Campus needs analysis. Your physical plant people can give you most or all of the information you need for a physical plant description.

Monitoring and energy demand analysis. Engineering and/or physics faculty can supervise students, and will probably be glad to. This is a good project for students. They can learn about building energy use and energy systems.

Environmental inputs. A faculty member in environmental studies would be glad to give students practical experience with environmental impact analysis.

Economic analysis and utility rates. You may be able to get help with the economic analysis, including energy price projections and utility rate structure, from somebody in the economics department or business school. If possible, find somebody who specializes in energy or utility economics.

Financing. Probably the business office and/or the development office will search for financing for the plant. But you may also want the advice of an investment counsel.

Legal matters. Start by talking to your university lawyer. But unless he happens to be an expert in utility law, he may not have enough experience in the field to meet all your legal needs. If you consult outside lawyers, he should work with them.

Working with consultants. You need close and constant contact with your consultants. Your physical plant staff has people who are familiar with the campus and heating plant and who have experience with other construction projects, particularly ones involving the heating system. The faculty probably includes mechanical or electrical engineers or physicists who know something about power plant design. These resource people can provide information for the conceptual design as the consultants need it, can help manage the conceptual design and coordinate the consultants' work, and can review and evaluate the results.

Working with Consultants

Finding and Evaluating Consultants

Your task force should figure out what has to be done for the campus needs analysis and conceptual design and whether each job can be done on campus (and by whom) or requires outside consultants.

To find appropriate consultants, ask your own faculty, people you know at other institutions, and community contacts like your building contractor. You may have to decide between someone local who does not have much cogeneration experience and someone from farther away. You may want to divide jobs between several consultants, for example, your local contractors for building modifications and electrical work, an engineering consultant for system design, and so forth. But avoid duplication of effort.

With your experience in other building projects and information you have gained reading this book, you should be ready to talk knowledgeably with the consultants you find. You need to evaluate their qualifications. Talk to other institutions they have worked for. You need to see if they are really prepared to cover all the tasks that need to be done. Check whether they can provide legal expertise in utility law, investments, and so forth. Find out if they are equipped to do a detailed analysis of noise control, for example.

Remember that you want your consultants, like your administrators, faculty, and staff, involved not just with the conceptual design but with the detailed design and with construction. You are embarking on a close and long-term relationship.

Cooperating with Your Consultants

Once you have consultants, your effective task force is enlarged. Your consultants should take part in and agree with all the decisions. Together, go over all that has been done and be ready to rework your plans. Your consultants will have their own ideas, which may well be better than yours. Redefine the tasks to be done. Make a revised set of schedules and budgets. The first set was surely naive. Agree on the managerial structure. Identify a person in each organization responsible for the tasks performed by that organization, and choose somebody, preferably from the school, to be responsible for coordinating the efforts of the different groups.

You are now ready to write a contract with each of your consulting firms. The contract should be as detailed as possible. It should specify what will be done and how results will be presented (written report or whatever). It should include an itemized cost agreement and a schedule.

APPENDIX A

Assumptions for Preliminary Analysis of Cogeneration Potential

All the assumptions made for the preliminary analysis section are listed in Table H.

Your object in the preliminary analysis is to make a crude estimate of the cost of cogenerated electricity for your campus and then to compare that estimate with the cost of purchased electricity. The cost of cogenerated electricity = capital cost (including interest and depreciation) + fuel cost + operation and maintenance cost − heat credit. The calculation assumes that your equipment is operated to meet on-campus thermal and electrical needs, so does not allow credit for sales. It also assumes that this is to be a modification of an existing system, so that extra thermal capacity is available as needed, and that there are additional costs for space and system modifications beyond the basic equipment costs.

Figure 11 on page 17 makes the basic comparison. The remaining three figures in the section refine the estimate. A difference of one point in the graphs corresponds to a change of $.005 in the cost of cogenerated electricity.

Calculations for diesels and gas turbines are lumped together for simplicity. In reality, gas turbines fall somewhere between diesels and steam turbines in costs and efficiencies.

Figure 11. These graphs compare the fuel price for cogenerated electricity with the price for purchased electricity. Capital costs for diesels/gas turbines are set at $1000/kw, for steam turbines at $2000/kw. For both, we assume a capacity factor (ratio of average annual electricity output to maximum possible output) of 0.75. A 10 percent return on investment is set at 6 points, corresponding to a moderate potential for cogeneration. Thus, for a diesel or gas turbine, capital cost/kwh = ($1000/kw × 10%) ÷ (8760 hours × 0.75) = 1.5¢/kwh.

Figure 12 (page 17). This pair of graphs adjusts for the variation in capital costs with size of plant. System costs are set as listed in Table H. We assume that your university has the electrical and thermal load curves shown in Figures 30 and 31. We further assume for this crude estimate that electrical and thermal demands are uncorrelated. Your annual electrical and thermal usage determine what size of plant would produce heat and electricity for your campus, given the 75 percent capacity factor assumed in Figure 11. A variation of $330/kwh in the capital cost corresponds to one point change in cogeneration potential.

Figure 13 (page 18). These graphs correct, very roughly, for deviations from the load curves. We assume that electrical load is likely to determine plant size for diesels/gas turbines and thermal load for steam turbines. Then we assume a significant change in cogeneration potential if your lowest three months of

TABLE H
Assumptions for Preliminary Analysis of Cogeneration Potential
(Based on 1979 prices and data)

	Diesel/Gas Turbine	Steam Turbine
Heat rate	10,000 Btu/kwh	22,000 Btu/kwh
Heat credit	4,000 Btu/kwh	18,000 Btu/kwh
Cost of operation and maintenance	0.5¢/kwh	0.25¢/kwh
Capital cost	750 kw $1330/kw 1500 kw $1000/kw 3 mw $670/kw	2 mw $2660/kw 4 mw $2330/kw 8 mw $2000/kw 16 mw $1670/kw

Calculations assume that equipment is operated to meet only on-campus thermal and electrical needs.
A difference of one point in the graphs corresponds to a change of 0.5¢ in the cost of cogenerated electricity.
Load curves are as shown in Figures 30 and 31.
Return on investment is assumed to be 10 percent.
Capacity factor is assumed to be 75 percent.

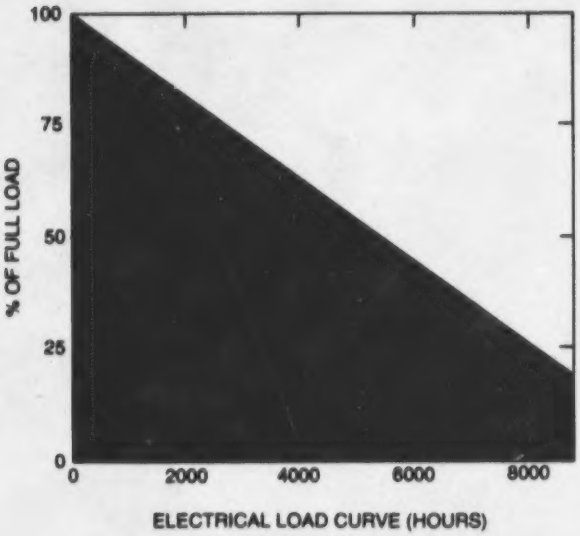

FIGURE 30. Electrical Load Curve

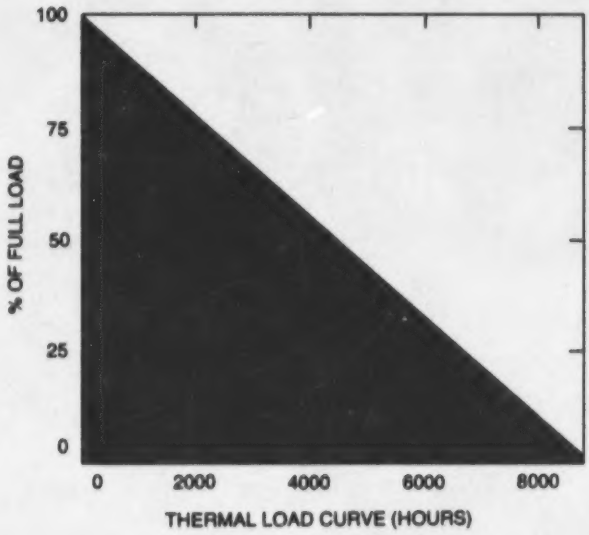

FIGURE 31. Thermal Load Curve

fuel use are sufficiently different from the average load curves to affect the capacity factor by more than 0.1.

Figure 14 (page 18). The basic idea of cogeneration is that you use fuel more efficiently than the electric utility. If the utility spends much less for its fuel than you do, your argument for cogeneration is weakened. If the utility spends more than you do, you may be able to make additional profit selling electricity. This pair of graphs makes allowance for cogeneration fuel costs of less than 80 percent or more than 150 percent of utility fuel adjustment charge.

APPENDIX B

Checklist on Legal and Regulatory Constraints

Where to go for advice
- State energy office
- State environmental office
- Local building code inspector
- University lawyer
- Environmental Protection Agency
- Department of Energy
- Occupational Safety and Health Administration

Community relations
- Keep the community and other concerned groups informed
  - press releases
  - fact sheets
- Keep channels of communication open in both directions
  - open meetings or hearings
  - discussions with local leaders (include both friends and enemies)
  - community input to design, scheduling, other considerations

Environmental constraints and regulations — what affects you and how do you deal with it?
- Air quality
  - Clean Air Act (EPA)
  - New Source Performance Standards (EPA, state environmental office)
  - calculation of maximum emission rates of criteria pollutants for your new plant (do it yourself)
  - attainment/nonattainment area and local subclassification (EPA, state environmental office)
- Solid waste disposal (state environmental office)
- Water discharges (state environmental office)
- Noise (state environmental office)
- Other: does your state have laws about emissions near wetlands or other special areas? (state environmental office)

Building regulations
- Building codes (local building code commission)
- Fire (local and state fire departments)
- Health and safety (OSHA)
- Federal or state regulations about modifications to historical buildings (architect)

Fuel conversion — Powerplant and Industrial Fuel Use Act of 1978 (DOE)

Sales of heat or electricity — will they affect your legal status?
- Are you a public utility? (state public utility commission)
- Will you violate your nonprofit charter? (university lawyer)
- Will you endanger your tax-exempt status? (university lawyer)

APPENDIX C

Checklist on Conceptual Design

Survey of sample systems

For each system determine:

- physical dimensions
- capital cost, including new construction or major building modification
- thermal efficiency
- electrical efficiency
- expected output
- fuel cost
- maintenance cost
- revenue

Compare systems

Identification of equipment

Include:

- engine
- generator
- heat recovery equipment
- fuel handling equipment
- exhaust system
- distribution systems
- end use equipment

For each item determine:

- costs
- dimensions and clearances
- full- and part-load thermal and electrical efficiencies
- emissions
- sound levels
- reliability
- operating and maintenance requirements
- replacement schedule

Layouts, efficiencies, emissions

Make sample layouts including all major equipment and connecting piping

Find mass flows and heat balances under full- and part-load conditions

From the balances determine thermal and electrical efficiencies

Prepare table of emissions under full load and estimate hourly and yearly emission rates for EPA criteria air pollutants under both full- and part-load operation

Find energy use:

- expected thermal and electrical outputs
- fuel requirements
- backup requirements for heat and electricity
- heat and/or electricity available for sale

Compare fuel use of present and cogeneration systems

APPENDIX D

Cogenerating Campuses

Institution	Contact Person (Name-Title)	Number and Types of Generating Systems	Fuel(s)	Electricity Generation Cap.	Electricity Produced 1979	Capacity of Central Plant Boilers
Bucknell University	John Bell Dir. Physical Plant	2 noncondensing steam turbines	coal	480 kw	825,000 kwh	90,000 lb/hr
Dartmouth College	Richard Plummer Dir. Physical Plant	3 back-pressure steam turbines	No. 6 fuel oil	3,000 kw	9,300,000 kwh	205,000 lb/hr
Iowa State University	William Whitman Dir. Physical Plant	5 condensing steam turbines	coal	36,250 kw	121,402,500 kwh	750,000 lb/hr
The Ohio State University	Thomas Smith Associate V.P. Physical Facilities	3 condensing steam turbines	natural gas, oil	14,000 kw	None	550,000 lb/hr
Oklahoma State University	G. D. Shepherd Dir. Physical Plant	1 condensing steam turbine, 3 noncondensing steam turbines	natural gas, No. 2 fuel oil	9,500 kw	25,000,000 kwh	273,000 lb/hr
Purdue University	W. E. Ahlers Dir. Engineering and Utilities	2 condensing steam turbines		7,500 kw	57,000,000 kwh	273,000 lb/hr
Saint Mary of the Woods College	Joseph Bisch Dir. Physical Plant	1 noncondensing steam turbine	coal	750 kw	400,000 kwh	90,000 lb/hr
University of California-Davis	Al Manenti Acting Manager, Buildings and Util. Div.	1 jet turbine	No. 2 fuel oil	7,000 kw	None	200,000 lb/hr
University of Illinois at Urbana	G. P. Porter Supt. of Utilities	6 condensing steam turbines, 1 noncondensing steam turbine	No. 2 fuel oil	30,000 kw	66,686,000 kwh	125,000,000 lb/hr
University of Iowa	Duane Nollsch Dir. Physical Plant	3 condensing steam turbines	coal, gas No. 6 fuel oil	30,000 kw	81,164,000 kwh	160,000 lb/hr
University of Massachusetts	T. P. deLesdernier Chief Utility Engineer	3 condensing steam turbines	coal	3,600 kw	16,300,000 kwh	420,000 lb/hr
University of Michigan	Kenneth Beaudry Utilities Systems Manager	4 noncondensing steam turbines	gas	26,500 kw	104,191,000 kwh	790,000 lb/hr

Institution	Contact Person (Name-Title)	Number and Types of Generating Systems	Fuel(s)	Electricity Generation Cap.	Electricity Produced 1979	Capacity of Central Plant Boilers
University of North Carolina at Chapel Hill	Robert Peake Dir. of Utilities	2 condensing steam turbines	fuel oil, natural gas, pulv. coal	12,500 kw	35,736,000 kwh	495,000 lb/hr
University of Northern Iowa	Mark Baethke Engineering Technician	1 noncondensing steam turbine (1981) 1 condensing steam turbine	oil, coal, natural gas	1,500 kw	12,442,730 kwh	400,000 lb/hr
University of Oklahoma	Chris Mason Manager of Power Plant	1 condensing steam turbine	natural gas	12,500 kw	44,440,000 kwh	360,000 lb/hr
University of Texas at Austin	Reuben Barr Asst. Supt. of Utilities	1 gas turbine	natural gas	60,000 kw	226,508,200 kwh	1,100,000 lb/hr
Virginia Polytechnic Institute	W. M. Sterrett Asst. V.P. for Administration	3 noncondensing steam turbines	coal, gas, oil	6,250 kw	25,000,000 kwh	70,000 lb/hr
Michigan State University	P. A. Nilsson Dir. Auto and Utilities	4 automatic extraction steam turbines	coal, gas	46,000 kw	166,152,000 kwh	1,150,000 lb/hr

Glossary

Terms are defined primarily as used in this manual. Often they have other meanings which are ignored here. Some terms useful for cogenerators are defined here although they do not appear in the manual.

absorption air conditioning. Air conditioning powered by steam or hot water.

accelerated depreciation. Assuming for tax purposes that a piece of property depreciates at a rate faster than its decline in market value.

alternative energy sources. Sources other than gas, oil, coal, and nuclear; for example solar, wind, photovoltaic, production of methane from waste, water, fuel cells.

attainment area. Region where concentration of a particular air pollutant does not exceed federal standards.

automatic extraction steam turbine. Steam turbine exhausting variable amounts of steam at given pressures. Can be condensing or noncondensing.

avoided cost. Cost to the electric utility of an additional kwh of electricity.

back-pressure steam turbine. A noncondensing steam turbine without extraction stages controlled by load.

backup. Additional source of supply to be used when normal source fails or is insufficient.

backup electricity. Power required when on-site generation facilities fail or are insufficient.

backup power. See backup electricity.

backup rate. Utility rate schedule for backup electricity.

BACT. Best Available Control Technology. Air pollution control technology required by the EPA for attainment areas. See LAER.

barrel of oil. 42 U.S. gallons. One barrel of residual oil can produce 6.2 million Btu; one barrel of distillate oil provides 5.8 million Btu.

base case. Estimate of operating savings.

baseload. Minimum demand, the demand that always exists.

baseload capacity. Output that can be produced continuously.

baseload demand. The minimum electrical demand on an electric utility. Typically 30 to 40 percent of peak demand.

best case. Result of setting all variables at most favorable amount.

block rate schedules. Utility rate schedules that charge by block, that is, the first so many kwh cost so much, the next so many cost another amount, and so forth.

boiler economizer. Fuel-saving device that uses heat from the exhaust gases of the boiler to preheat water entering the boiler.

Btu. British thermal unit. Heat needed to raise one pound of water one degree Fahrenheit. 1 kwh = 3412.7 Btu; one gallon residual oil = 148,000 Btu; one cup of hot coffee = approximately 30 Btu.

campus needs analysis. Survey of campus energy needs.

campus use pattern. Pattern of day-to-day building use on campus.

capacity. Maximum amount that the system can produce.

capacity credits. Credit given by the utility for power it buys, based on the generator's ability to reduce or postpone the need for new utility generating plants.

capacity factor. Ratio of actual annual electricity output to maximum possible output.

capital cost. Cost of design and construction of a facility, and for equipment and its installation.

capital investment. Money spent to buy a facility or property.

capital payments. Annual payments on capital investment.

cash flow. Net transfers of money.

Clean Air Act. Federal law passed in 1967, amended in 1970 and 1977, which regulates control of air pollution.

clean fuel. Fuel that produces little air pollution, like low-sulphur oil or coal, low-nitrogen fuels, low-ash coal. Pipeline-quality natural gas is the cleanest of all common fossil fuels.

CO. Carbon monoxide. Comes partly from incomplete burning of carbon-containing fuels, as in car exhaust. One of the five criteria air pollutants.

cogeneration. The simultaneous production of electric power and other forms of useful energy, like heat or process steam, from the same facility.

conceptual design. Specification of major components of a system and their operating characteristics, layout, space needs, and operating and maintenance requirements.

condensate. Water produced by cooling of steam.

condensing steam turbine. Steam turbine that produces additional electricity by expanding steam to very low pressures while generating power. Exhaust steam is converted to water in a condenser.

control system. Centralized system that regulates heat or electricity use. System that regulates power plant operation.

criteria air pollutants. Five air pollutants for which national ambient air quality standards have been set by the EPA: sulfur oxides (SO_x), total suspended particulates (TSP), carbon monoxide (CO), photochemical oxidants, and nitrogen dioxide (NO_2). Guidelines exist for hydrocarbons (non-methane).

degree days. Difference between average of highest and lowest daily temperature and 65°F (heating) or 72°F (cooling).

demand. Amount of heat or electricity required per unit of time.

demand charge. A monthly charge for electricity based on the month's peak demand in a specified period, for instance 15 minutes.

demand curve. See utility demand curve.

detailed design. Final engineering and architectural design.

diesel. Internal combustion engine that ignites its fuel by compression. A car engine ignites its fuel by spark.

diesel fuel. See distillate oil.

discount rate. A measure of how much less income is worth to an investor when it is deferred one year.

distillate oil. A light petroleum product used for home heating and for most machinery. Also called number two oil, diesel fuel.

distribution system. 1) The pipelines and electric lines that carry heat and electricity from their point of origin on campus to the end-use equipment. 2) Low voltage lines connecting the electric utility transmission system to customers.

district heating or cooling. Central system for heating and cooling the buildings within a district. Eliminates the need for individual building heating or cooling devices.

DOE. Department of Energy. The federal, cabinet-level department responsible for energy research, development, and policy.

double extraction steam turbine. Extraction steam turbine with two extraction stages. Can be condensing or noncondensing.

down time. Time when equipment is not operating. Outage.

ebulliently cooled. Cooled by converting water to steam.

efficiency. Percentage of energy input converted to useful output.

electric generating capacity. Maximum rate at which the system can generate electricity.

electrical capacity. See electric generating capacity.

electrical resistance heating. A system that generates heat by passing electricity through low-resistance material.

electricity load curve. Plot of electricity demand against time such that, for any given number of hours, the power level is at least as great as shown on the graph.

electricity-steam output ratio. Proportion of electricity to steam produced by a cogeneration system.

electricity-steam ratio. See electricity-steam output ratio.

emission offset. A reduction in the emissions of existing sources to more than compensate for emissions from new sources.

end-use equipment. Equipment that uses electric or thermal energy for such services as space heating and cooling, ventilation, domestic hot water, lighting, and cooking.

energy charge. Charge for electricity based on the number of kwh used.

energy conservation tax credit. Under the National Energy Act (NEA), tax credit for investments in energy conservation.

energy value. Comparative measure of forms of energy, depending on usefulness and difficulty of production. Electricity is more valuable than heat. High-temperature heat is more valuable than low-temperature heat.

environmental impact. Any effect on the environment.

EPA. Environmental Protection Agency. Federal agency responsible for protecting and improving the environment.

extraction steam turbine. Steam turbine exhausting steam, or steam and hot water, at more than one pressure.

feasibility study. A preliminary study to determine whether a course of action is possible and what its effects are likely to be.

FERC. Federal Energy Regulatory Commission. Federal agency regulating dams, interstate electricity transmission and sales, and interstate natural gas and oil pipelines.

first year return. Profit on an investment in the first year.

fluidized bed combustion. Burning of pulverized coal in a bed of crushed limestone kept in motion by the flow of air or combustion gases.

fossil fuels. Fuels made from the deposits of organic matter grown eons ago and acted on by geological forces and millions of years. Oil, natural gas, and coal are major commercial examples.

fuel adjustment charge. Electric utility's average fuel cost per kwh, passed through to the customer.

fuel cell. Device somewhat like a battery, which converts the chemical energy of a fuel directly into electricity.

full load. Maximum demand on electrical or thermal equipment or systems.

gas engine. Internal combustion engine like a car's, but using gaseous fuel instead of liquid gasoline. Not to be confused with gas turbine.

gas turbine. Device for generating electricity and mechanical energy, containing sets of windmill-like blades turned by combustion gases. Not to be confused with a gas engine.

generator. Any device for producing electricity.

grid. Electrical utility's system of cables, transformers, and stations for distributing power.

grid connection. Joining an electric system containing a generating plant to an electric utility's system so that electricity can flow in both directions.

heat balance. Energy flow in a power generating system.

heat pump. Device that extracts heat from a cool place and moves it to a warmer place, like an air conditioner running in reverse.

heat rate. Fuel input required to produce a unit of electrical output, commonly measured in Btu/kwh.

heat recovery system. Equipment for recovering byproduct heat from an electric generating system.

heating value. Chemical energy in fuel available as useful heat. The heating value of one gallon of residual oil is 148,000 Btu.

HEW. Department of Health, Education, and Welfare. A federal, cabinet-level department, now the Health and Human Services Department.

hph. Horsepower-hour. A unit of energy. 1 hph = 0.746 kwh.

hydrocarbons (non-methane). Mixture of organic compounds found in exhausts and oil vapors. See photochemical oxidants.

incremental cost. Cost for an additional kwh of electricity.

internal rate of return. Discount rate at which present value of an investment is equal to the investment.

interruptible. Describes service that can be curtailed by the utility when the utility's demand is high.

investment counsel. Lawyer specializing in investment law.

investment tax credit. Tax credit for capital investment in plants and equipment.

jacket. Engine block.

kw. Kilowatt. The amount of power used by ten 100-watt light bulbs.

kwh. Kilowatt-hour. The amount of energy used by ten 100-watt light bulbs in one hour. One kwh = 3414 Btu.

LAER. Lowest Achievable Emissions Rate. Standards required by the EPA for nonattainment areas. See BACT.

landfill. Site for disposing of solid waste.

layout. Drawing showing arrangement of equipment.

leveraged lease. Arrangement wherein an investor buys a plant for tax advantages and leases it to the university, often with an agreement to sell it to the university after a specified time.

line. Pipeline. Electric cable.

load. Demand on electrical or thermal equipment or systems.

load curve. See electricity or thermal load curve.

load following. Matching production to demand.

maintenance cost. Cost for servicing and repair of equipment, including parts and labor.

marginal cost. See incremental cost.

mass flow. Flow of material (fuel, steam, hot water, exhaust gases) in the system.

maximum contracted demand. Largest amount of service the utility agrees to provide.

μg. Microgram. One millionth of a gram. 454 million micrograms weigh one pound.

modeling. Computer simulation of pollutant dispersion to determine a source's effects on air quality in an area.

monitoring. Measuring air pollutant concentrations and weather conditions to determine air quality.

mw. Megawatt. 1000 kw.

National Ambient Air Quality Standards. Maximum allowable concentrations of air pollutants set by the EPA.

NEA. National Energy Act. Comprehensive energy act passed by the federal government in 1978, consisting of five bills: the National Energy Conservation Policy Act of 1978 (NECPA), the Powerplant and Industrial Fuel Use Act of 1978, the Public Utilities Regulatory Policy Act of 1978 (PURPA), the National Gas Policy Act of 1978, and the Energy Tax Act of 1978.

NECPA. National Energy Conservation Policy Act of 1978 (Public Law 95-619). Part of the National Energy Act dealing with national energy conservation policy.

needs analysis. See campus needs analysis.

net energy cost. Cost of cogeneration and backup fuel plus cost of standby electricity minus energy sales revenues.

net savings. Operating savings minus capital payments.

NO_2. Nitrogen dioxide. Component of exhaust gases, including car exhaust. One of the five criteria air pollutants.

NO_x. Nitrogen oxides. General term including nitrogen dioxide (NO_2) and nitric oxide (NO). NO_x often forms during high temperature combustion.

nonattainment area. Geographic region where concentration of one or more of the criteria air pollutants exceeds federal standards.

noncondensing steam turbine. Steam turbine from which exhaust steam is not condensed.

NSPS. New Source Performance Standards. Maximum allowable pollutant emissions for certain categories of new stationary sources, set by the EPA.

Number 6 oil. See residual oil.

Number 2 oil. See distillate oil.

O_3. Ozone. O_3 concentration correlates well with photochemical oxidant concentration and is used as a measure by the EPA.

off-peak. Times when power demand is below average. For electric utilities, generally nights and weekends.

offset. See emission offset.

oil. See residual oil or distillate oil.

operating cost. (1) Total cost for operating a plant, including fuel, maintenance, labor, and the like. (2) Labor cost.

operating savings. Annual operating cost difference between cogenerating and conventional plants.

OSHA. Occupational Safety and Health Administration. Federal agency responsible for health and safety in the workplace.

outage. See down time.

partial load. Less than maximum demand on electrical or thermal equipment or systems. See full load.

particulates. See TSP, total suspended particulates.

payback time. Time needed for complete return of original capital investment.

peak demand. Maximum amount required.

peak period. Times of high demand.

peak shaving. Reducing peak demand.

photochemical oxidants. Chemicals created when hydrocarbons and other organic compounds react with nitrogen oxides in the presence of sunlight. One of the five criteria air pollutants.

photovoltaic cell. Device that produces electricity from light.

Powerplant and Industrial Fuel Use Act of 1978. Part of the National Energy Act dealing with energy conservation and alternative fuels for powerplants and industries.

present value of investment. Total income from an investment calculated with the future income discounted by some appropriate rate.

process steam. Steam used for industrial operation or process.

PSD. Prevention of Significant Deterioration. Federal regulations to protect air quality in areas that meet federal air quality standards (attainment areas).

psig. Pounds per square inch, gauge pressure. Gauge pressure is pressure relative to atmospheric pressure.

PURPA. Public Utility Regulatory Policy Act. Part of the National Energy Act of 1978, requiring electric utilities to

buy power from generating facilities using alternative technologies, including cogeneration. PURPA requires electric utilities to pay at a rate reflecting their true avoided or incremental cost, including capital cost.

rate base. Utility capital investment on which its rates are calculated.

rate schedule. Price list showing how the electric bill of a class of customers will be calculated.

rate structure. See rate schedule.

reciprocating engine. Engine with pistons and cylinders.

residual oil. Number 6 oil. A heavy and only slightly processed oil used, for example, in large boilers and large machinery. Generally the least expensive petroleum fuel. May need cleaning before use.

sensitivity analysis. Calculation of the variation in the base case caused by variation of selected parameters.

single extraction steam turbine. Extraction steam turbine with one extraction stage. Can be condensing or noncondensing.

SIP. State Implementation Plan. Plan a state must make to ensure that the requirements of the Clean Air Act, amended in 1977, are met.

skimming tank. Tank in a fuel treatment system for collecting the washed oil from the wash water.

SO_2. Sulfur dioxide. One of the sulfur oxides.

standby. See backup.

standby connection. Connection to utility grid for backup electricity.

standby electricity. See backup electricity.

steam turbine. Device for generating electricity and mechanical energy, containing sets of windmill-like blades turned by steam from a boiler.

Stirling engine. External combustion reciprocating engine.

sulfur oxides. Group of gaseous compounds coming primarily from burning sulfur-containing fossil fuels. Includes sulfur dioxide. One of the five criteria air pollutants.

thermal backup. Heat required when cogeneration facilities fail or are insufficient.

thermal capacity. Maximum amount of heat the system can produce.

thermal efficiency. Ratio of useful heat output to fuel input.

thermal load curve. Plot of thermal demand against time such that for any given number of hours the thermal demand is at least as great as shown on the graph.

total energy system. Cogeneration system able to fill all electricity and heat needs independent of the electric utility.

transmission loss. Electricity lost in high-voltage transmission lines. The difference between electricity produced in utility generators and the electricity delivered to the distribution substations.

transmission system. High-voltage lines connecting electric utility generators with the distribution system.

TSP. Total suspended particulates. They may be solid or liquid, may come from incomplete combustion, road dust, and many other sources, and may both injure lungs directly and exacerbate effects of other pollutants. One of the five criteria air pollutants.

uncertainty. Amount of variation possible in a given parameter or system. See best case, worst case.

uncontrolled extraction steam turbine. Steam turbine exhausting fixed amounts of steam at given pressures. Can be condensing or noncondensing.

unit train. Train with a single destination, a single type of load (often coal), and often its own track.

use pattern. See campus use pattern.

utility demand curve. Demand on the utility for electricity as a function of time.

utility distribution system. Lines and transformers from a substation to the facilities serviced.

waste heat boiler. Boiler heated by hot exhaust.

wheeling. Using a utility's transmission lines to transfer power from another source to a customer, usually another electric utility.

worst case. Result of setting all variables at least favorable amount.

Notes

[1]Roy J. Faddis and Charles McClure, "The Performance of Operating Total Energy Plants," *Proceedings of the International Conference on Energy Use Management*, Tucson, 1978.

[3]"Dow Chemical Company Study," *Cogeneration of Steam and Electric Power*, ed. Robert Noyes, Noyes Data Corp., NJ, 1978, p. 3.

[3]"Thermo Electron Corporation Study,"*Cogeneration of Steam and Electric Power*, ed. Robert Noyes, Noyes Data Corp., NJ, 1978, p. 42.

[4]"Dow Chemical Company Study," *Cogeneration of Steam and Electric Power*, ed. Robert Noyes, Noyes Data Corp., NJ, 1978, p. 4.

[5]Ibid.

[6]*The Federal Register*, February 25, 1980, p. 12214.

[7]*The Federal Register*, March 20, 1980, p. 17959.

[8]"A Technical Overview of Cogeneration: Resource Planning Associates Study," *Cogeneration of Steam and Electric Power*, ed. Robert Noyes, Noyes Data Corp., NJ, 1978, p. 225.

[9]Robert H. Williams, "Designing a Coal Conversion Policy Compatible with an Optimal Fuels Policy for Cogeneration, Comments on the Powerplant and Industrial Fuel Use Act of 1978," Testimony presented to the Department of Energy, Public Hearing Management Docket No. ERA-R-78-19, revised March 2, 1979.

[10]*Energy Alert 79-1: Energy Audit Procedures:* Suggested Procedures for Energy Audits, for use under Title III of the National Energy Conservation Policy Act of 1978 (Public Law 95-619), Energy Task Force, ACE, APPA, NACUBO, Washington, D.C., February 16, 1979.

[11]"Minnesota Starts Cogeneration Project With Purchase of Generating Plant," *APPA Newsletter*, Vol. 26, No. 6, June 1978.

[12]"A Preliminary Feasibility Study of a Grid-Connected Community Energy System at Clark University," Vol. 2, ERDA Report COO-4211-1, Worcester, August, 1977.

[13]"Grid-Connected Integrated Community Energy System, Executive Summary," ERDA Report COO-4210-1, University of Minnesota, Minneapolis, June, 1977.

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